MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 16, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
or
o 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 incorporation or organization)	(I.R.S. Employer Identification No.)
Magellan GP, LLC P.O. Box 22186, Tulsa, Oklahoma	74121-2186
(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 x No o
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 o No x
Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
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. x
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.
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o Emerging growth company o

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

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

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 30, 2017 was $16,213,584,044.

As of February 15, 2018, there were 228,195,160 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 2018 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.
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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.

(b) Financial Information About Segments

See Part II—Item 8. Financial Statements and Supplementary Data, Note 16 – 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, 2017, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 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 storage facilities with an aggregate storage capacity of approximately 28 million barrels, of which approximately 17 million are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

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 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 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 and condensate are used as feedstocks by refineries and petrochemical facilities;

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

- ammonia is primarily used as a nitrogen fertilizer.

Except for ammonia, 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 Gulf Coast and covering a 15-state area across the central U.S. The system includes approximately 44 million barrels of aggregate usable storage capacity at 53 connected terminals. Our network of independent terminals includes 26 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,		
	2015	2016	2017
Percent of consolidated revenue	73%	71%	72%
Percent of consolidated operating margin	61%	57%	58%
Percent of consolidated total assets	50%	49%	47%

See Note 16—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 2017, 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 published tariffs filed with the Federal Energy Regulatory Commission ("FERC") or appropriate 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.

In 2017, the products transported on our refined products pipeline system were comprised of 60% gasoline, 33% distillates and 7% aviation fuel and LPGs. The operating statistics below reflect our refined products pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2015	2016	2017
Shipments (million barrels):			
Gasoline	268.1	275.4	295.5
Distillates	152.5	150.2	166.2
Aviation fuel	21.2	25.7	26.5
LPGs	9.7	10.4	9.9
Total shipments	451.5	461.7	498.1

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. Furthermore, 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.

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. We typically 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 81% of the total product margin for the refined products segment during 2017. When the differential between the cost of butane and the price of gasoline narrows, the product margin we earn from these activities is negatively impacted.

We also operate three fractionators along our pipeline system that separate transmix, which is an unusable mixture of various refined products, into separated 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 separated refined products.

Product margin from commodity-related activities in our refined products segment was $180.5 million, $101.8 million and $130.4 million for the years ended December 31, 2015, 2016 and 2017, respectively. The amount of margin we earn from these activities fluctuates with changes in petroleum prices. 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 16—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, including 120,000 barrels of butane storage, near Atlanta, Georgia. Powder Springs began operations in first quarter 2017.

Markets and Competition. Shipments originate on our refined products pipeline system from direct connections to refineries, through interconnections with other pipelines or at our 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 49% of U.S. refining capacity, and in particular is well-connected to 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 February 2018 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 2017, approximately 66% of the products transported on our refined products pipeline system originated from 19 direct refinery connections and 34% originated from connections with other pipelines or terminals.

As set forth in the table below, our system is directly connected to and receives product from the following refineries:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
Andeavor	St. Paul, MN
Andeavor	El Paso, TX
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	Galveston Bay, TX
Marathon	Texas City, TX
Phillips 66	Ponca City, OK
Sinclair	Evansville, WY
Suncor Energy	Commerce City, CO
Valero	Ardmore, OK
Valero	Houston, TX
Valero	Texas City, TX
Wyoming Refining	Newcastle, WY

Our system is also connected to multiple pipelines and terminals, including those shown in the table below:
Major Origins—Pipeline and Terminal Connections (Listed Alphabetically)

Pipeline/Terminal	Connection Location	Source of Product
BP	Manhattan, IL	Whiting, IN refinery
CHS	Fargo, ND	Laurel, MT refinery
Explorer	Glenpool, OK; Mt. Vernon, MO; 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 Terminals Holdings	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, pricing 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, most of 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. Our system competes primarily with ammonia shipped by rail carriers and in certain markets with a third-party ammonia pipeline.

Customers and Contracts. Our refined products pipeline system ships products for several different types of customers, including independent refiners and integrated oil companies, wholesalers, retailers, traders, railroads, airlines, bio-fuel producers 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, as well as utilities who use propane as a fuel source. 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 2017, 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, 2017. 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, 2017, 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, 2017 represented 35% of total revenue for our refined products segment and 55% of revenue excluding product sales.

Customers of our independent terminals include independent and integrated oil companies, 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.

Our ammonia pipeline system ships product for three customers who own production facilities connected to our system. We have contracts with these customers that contain minimum volume commitments whereby a customer must pay for unused pipeline capacity if the customer fails to ship its committed volume. One of these contracts will expire in 2019, and the other two will expire in 2020.

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

CRUDE OIL

Our crude oil segment, including all of the assets of our joint ventures, is comprised of approximately 2,200 miles of crude oil pipelines with an aggregate storage capacity of approximately 28 million barrels, of which 17 million are used for contract storage. The crude oil segment includes: (i) the Longhorn pipeline; (ii) a Cushing, Oklahoma storage terminal; (iii) the Houston-area crude oil distribution system; (iv) the crude oil components of our East Houston, Texas terminal; (v) the crude oil components of our Corpus Christi, Texas terminal, including our condensate splitter; (vi) the Gibson, Louisiana terminal; and (vii) our interests in BridgeTex Pipeline Company, LLC (“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,		
	2015	2016	2017
Percent of consolidated revenue	19%	20%	20%
Percent of consolidated operating margin	30%	32%	33%
Percent of consolidated total assets	38%	39%	38%

See Note 16–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 paid by shippers on our crude oil pipelines and storage fees paid by our crude oil terminal customers. 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-area crude oil distribution system.

Our East Houston terminal includes approximately eight million barrels of crude oil storage, with approximately five million barrels used for contract storage and three 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-area crude oil distribution system and to third-party pipelines, including the Houston-to-Houma pipeline, and Argus’ West Texas Intermediate (“WTI”) Houston price assessment is based on trades at the terminal.

Our Houston-area crude oil 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 Texas City, Texas and crude oil import and export facilities. 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 12 million barrels of crude oil storage, of which two million barrels are reserved for working inventory, leaving 10 million barrels 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 Saddlehorn, 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

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one million barrels of related storage is also located at our terminal in Corpus Christi.

Joint Venture Activities. We own a 50% interest in BridgeTex, a joint venture with an affiliate of Plains All American Pipeline, L.P. (“Plains”). BridgeTex owns an approximately 400-mile pipeline currently capable of transporting up to 400,000 bpd of Permian Basin crude oil from Midland and Colorado City, Texas to our East Houston terminal. We are currently in the process of expanding the pipeline capacity to 440,000 bpd and expect this project to be complete by early 2019. We receive management fees to operate BridgeTex, which we report as affiliate management fee revenue on our consolidated statements of income. We entered into a long-term lease agreement with BridgeTex to provide it with capacity on our Houston-area crude oil distribution system, and we receive capacity lease revenue from this agreement, which is included in transportation and terminals revenue on our consolidated statements of income.

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 that is included in our transportation and terminals revenue on our consolidated statements of income.

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.

We own a 40% interest in Saddlehorn, a joint venture with an affiliate of Plains (40% interest) and an affiliate of Anadarko Petroleum Corporation (20% interest). Saddlehorn owns an undivided joint interest in an approximately 600-mile pipeline, which delivers various grades of crude oil primarily from the DJ Basin region of Colorado to storage facilities in Cushing, including our own Cushing terminal. Saddlehorn has the capacity to deliver up to 190,000 bpd of crude oil. We receive management fees to operate Saddlehorn, which we report as affiliate management fee revenue on our consolidated statements of income. We also receive storage revenue from Saddlehorn, which we include in transportation and terminals revenue in our consolidated statements of income.

We own a 50% interest in Seabrook, a joint venture with an affiliate of LBC Tank Terminals, LLC (“LBC”). Seabrook owns approximately 700,000 barrels of crude oil storage located adjacent to LBC’s existing terminal in Seabrook, Texas and a pipeline that connects Seabrook’s storage facilities to an existing third-party pipeline that began transporting crude oil to a Houston-area refinery in the second quarter of 2017. Seabrook is in the process of constructing an additional 1.7 million barrels of crude oil storage and will construct a new pipeline to connect its facility to our Houston-area crude oil distribution system, expected to be operational in mid-2018. We receive management fees for operating the pipeline activities of Seabrook, which we record in affiliate management fee revenue on our consolidated statements of income.

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-area crude oil 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-area distribution facilities compete 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 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 for its supply and competes primarily with other pipelines and supply alternatives that are capable of transporting crude oil from the DJ Basin production area to Cushing. 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. Spot barrel movements on our pipelines generally ship at higher rates than those charged to committed shippers. We typically reserve at least 10% of the shipping capacity of our pipelines for spot 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 customer agreements that expire September 30, 2018. For 2017, approximately 54% of the shipments on our wholly-owned crude oil pipelines were subject to such commitments. The average remaining life of these contracts was approximately one year as of December 31, 2017. As of December 31, 2017, approximately 77% 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, 2017. 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 five years.

MARINE STORAGE

We own and operate five marine storage terminals located along coastal waterways with approximately 26 million barrels of aggregate storage capacity, including approximately one million barrels of storage jointly owned through our Texas Frontera, LLC joint venture ("Texas Frontera"). Our joint venture, MVP Terminalling, LLC ("MVP"), is constructing an additional marine storage terminal along the Houston Ship Channel in Pasadena, Texas. Our marine terminals provide distribution, storage, blending, inventory management and additive injection services for refiners, marketers, traders and other end users of petroleum products.

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

	Year Ended December 31,		
	2015	2016	2017
Percent of consolidated revenue	8%	9%	8%
Percent of consolidated operating margin	9%	10%	8%
Percent of consolidated total assets	11%	12%	12%

See Note 16–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 long-term 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 currently stores a mix of refined products, blendstocks, heavy oils and crude oil. This facility 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-area crude oil 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 primarily 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 primarily 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 primarily 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. This storage is contracted under a long-term agreement with an affiliate of Texas Frontera. We receive a fee for operating the storage tanks of Texas Frontera, which we recognize as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in MVP, which was formed in September 2017 to construct and develop a refined products marine storage terminal along the Houston Ship Channel in Pasadena, Texas. The facility will initially include five million barrels of storage, truck loading facilities, pipeline connections and two proprietary ship docks. We serve as construction manager and will serve as operator of MVP when construction is complete. We receive management fees for our services, which we recognize as affiliate management fee revenue on our consolidated statements of income. A portion of this facility is expected to be operational in early 2019, with the next phase expected to be operational in early 2020.

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 strong 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 2017, approximately 90% of our storage terminal capacity was utilized with the remaining 10% not utilized primarily due to tank integrity work throughout the year, including integrity work related to tanks damaged by Hurricane Harvey. As of December 31, 2017, approximately 83% of our usable storage capacity was under contracts with remaining 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, 2017. 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 2015, 2016 or 2017.

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, product overages and certain crude oil inventories. We use derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale activities. Our strategies are primarily intended to mitigate and manage price risks that are inherent in our commodity positions. 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 our risks.

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 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 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 2017 and expect to satisfy the requirements for 2018 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, 2015, 2016 and 2017, 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 remedial 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 remediation 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 $24.0 million and $19.3 million at December 31, 2016 and 2017, 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 $4.1 million and $7.2 million at December 31, 2016 and 2017, 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.

As part of our assessment of facility operations, we have identified some above-ground tanks at our terminals that either are or are suspected of being coated with lead-based paints. The removal and disposal of any paints that are found to be lead-based, whenever such activities are conducted in the future as part of our day-to-day maintenance activities, will require increased handling. However, we do not expect the costs associated with this increased handling to be material.

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.

Congress has from time to time considered legislation to reduce emissions of greenhouse gases. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions (“Paris Agreement”). The Paris Agreement became effective in November 2016 after more than 70 countries, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In August 2017, the current administration announced that the United States plans to withdraw from the Paris Agreement and to seek negotiations to reenter the Paris Agreement on different terms or establish a new framework. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. To the extent the United States and other countries impose other climate change regulations on the oil industry, it could have an adverse direct or indirect effect on our business.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations that limit or regulate emissions of greenhouse gases could adversely affect demand for the products that we transport, store and distribute and, depending on the particular program adopted, could 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 greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas 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

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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 ("HLPSA"), 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 interstate 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. PHMSA defines a breakout tank as one that is used to relieve surges in a hazardous liquid pipeline system or to receive and store hazardous liquids transported by a pipeline for reinjection and continued transportation by a pipeline. In January 2015, amended regulations were published by PHMSA which require more frequent out-of-service inspections for breakout storage tanks. These regulations would impact approximately 500 of our storage tanks. We remain in active discussions with PHMSA to consider alternative, technically-viable inspection intervals. If we are unable to reach such an agreement with PHMSA, our compliance with the amended regulations could negatively impact our future financial results and could result in service disruptions to our customers.

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. At qualifying facilities, we are subject to OSHA

Process Safety Management regulations that are designed 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 January 2017. 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 physical security regulations depending on the nature of the facility. Our assets can be 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, 2017, we had 1,802 employees, 940 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 24% of the 940 employees are represented by the United Steel Workers ("USW") and covered by a collective bargaining agreement that expires in January 2019. At December 31, 2017, 151 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. 177 employees were assigned to our marine storage segment at December 31, 2017, primarily in the Gulf and East Coast regions of the U.S. Approximately 16% of these employees are represented by the International Union of Operating Engineers ("IUOE") 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 16–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

We file annual, quarterly and current reports, proxy statements and other information electronically with the Securities and Exchange Commission ("SEC"). You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including our filings.

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 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 or state regulations. For example, the National Highway Traffic Safety Administration and the EPA finalized standards for passenger cars and light trucks manufactured in model years beginning in 2017 that will require significant 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 or control; and

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

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, 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 and 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. While the transportation revenues on our crude oil pipelines are in some cases supported by long-term contracts, lower production in the regions served by our pipelines could result in lower shipments of uncommitted volumes, 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 material 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 substantially 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 storage 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 existing contracts on our Longhorn crude oil pipeline expire in late 2018, and we currently expect to receive rates below the existing rates following the expiration of the contract term. Failure by our customers to renew any of their contracts with us on terms and at rates substantially similar to our existing contracts could result in lower utilization of our assets or cause our revenues to decline or be more volatile, any of which could adversely affect our results of operations, financial position and our ability to make cash distributions.

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

We compete with other existing 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 have subsequently submitted requests for further clarification or rehearing from the FERC. 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. We have also constructed a condensate splitter in Corpus Christi, Texas, and are in the process of constructing a new marine terminal along the Houston Ship Channel in Pasadena, Texas. Similar investments have been made and additional investments may be made in the future by our competitors or by new entrants to the markets we serve. 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 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, and we could experience difficulty in replacing those lost volumes and revenue. 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. If the prices of petroleum products become relatively stable, or if federal or state 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, either of which could materially reduce 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. Prices of petroleum products have historically experienced wide fluctuations. 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. Additionally, significant fluctuations in market prices of petroleum products could result in significant 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 results of operations.

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, any non-compliance with our risk management policies 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 under Accounting Standards Codification 815, Derivatives and Hedging, or if they result in material amounts of ineffectiveness, we could experience material fluctuations in our quarterly or annual 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, 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.

We use the FERC's PPI-based price indexing methodology to establish tariff rates in certain markets served by our pipelines. 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, as it did in 2015, requiring us to reduce our index-based rates, as we did in July 2016, 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.

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 the partnership's operations located in Houston and Corpus Christi. This hurricane negatively impacted our results by approximately $20 million. These 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, 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 and gathering systems on land owned by third parties and 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 have the right of eminent domain over land owned by Native American tribes or other government entities and our ability to secure required permits and rights-of-way or otherwise proceed with construction of our expansion projects could encounter opposition or sabotage from activists, who may attempt to delay pipeline construction through protests and other means, as recently occurred in North Dakota in relation to the Dakota Access Pipeline ("DAPL"). 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 and, in some cases, those of other pipelines, could have a material adverse effect on our business. Similarly, any terrorist attacks that severely disrupt 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, plants and assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, "hacktivists," or private individuals. The age, operating

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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 gain access to information related to our assets through 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 reside 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 intend to 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, including in some cases through the exercise of the power of eminent domain, 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 other means, as has recently occurred in North Dakota in relation to DAPL. Further, in many instances, the operations of our expansion projects are subject to the execution 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 execution 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 increase cash distributions to our unitholders.

Our ability to 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 value for our unitholders. If we are unable to acquire new assets or develop additional expansion projects, our ability to increase distributions to our unitholders will be reduced.

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 $1.3 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. 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.

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. For example, $250 million of our long-term notes will mature in July 2018 and an additional $550 million will mature in 2019. We anticipate refinancing those notes when they mature.

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, 2017, the face value of our outstanding fixed-rate debt was $4.6 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, 2017, we were engaged in eight joint ventures in which we share control with other entities according to the relevant joint venture agreements. Those agreements provide that the respective joint venture management committees, including our representatives along with the representatives of the other owners of those joint ventures, 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 joint venture'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 to 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, and 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 are constructing a new 135-mile pipeline from East Houston to Hearne, Texas at an estimated cost of $425 million based on a limited number of 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 will be operated by our joint venture co-owner, LBC Tank Terminals, LLC, which also 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 a commercial bank 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 a broker. A failure of our commercial bank or our broker 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 rates. 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 rates 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 pipeline. 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 pipeline. 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.

In July 2016, the D.C. Circuit issued a decision in United Airlines Inc. v. FERC that found that FERC had acted arbitrarily and capriciously when it permitted an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in its rates. The court remanded the case to the FERC to allow it to have an opportunity to provide a reasoned basis for its decision on income tax allowances for partnership pipelines. We are unable to predict how the FERC will respond to the court's remand. If the FERC were to no longer allow limited partnerships to include income tax allowance in their cost of service, our cost of service would be reduced, which could ultimately impact our tariff rates if we were ever required to adopt a cost-of-service ratemaking methodology.

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 50% interest, in filings with the FERC and Railroad Commission of Texas ("RRC"), alleging that the tariffs for the new capacity are discriminatory. In January 2018, regulators from multiple states requested that the FERC reduce allowed rates for pipelines and public utilities in order that tax benefits realized by regulated entities from recent tax reform legislation be "passed on" to their customers. 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 HLPSA, the Pipeline Safety, Regulatory 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 federal, state and provincial 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 may 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 these 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 protestors, who may attempt to delay pipeline construction through protests, sabotage and other means, as has recently occurred in North Dakota in relation to DAPL. 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 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 safety regulations in January 2017. 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 federal and state authorities and have encountered political opposition that could result in increased regulatory costs or delays. For example, referendums in the state of Colorado, from where most of the volume on our Saddlehorn joint venture originates, sought to restrict hydraulic fracking in that state. While these referendums failed to receive sufficient support to get on the ballot, 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.

Congress has from time to time considered legislation to reduce emissions of greenhouse gases. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions (“Paris Agreement”). The Paris Agreement became effective in November 2016 after more than 70 countries, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In August 2017, the current administration announced that the United States plans to withdraw from the Paris Agreement and to seek negotiations to reenter the Paris Agreement on different terms or establish a new framework. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. To the extent the United States and other countries impose other climate change regulations on the oil industry, it could have an adverse direct or indirect effect on our business.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations that limit or regulate emissions of greenhouse gases could adversely affect demand for the products that we transport, store and distribute and, depending on the particular program adopted, could 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 greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas 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, increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect 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 and local 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 have the authority to prescribe specific product quality specifications for commodities sold into the public market. Changes in product quality specifications or blending requirements could 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, 2017, 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, 2017, we had $5.6 billion of net property, plant and equipment, $1.1 billion of investments in non-controlled entities, $53.3 million of goodwill, and $52.8 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. 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.

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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, acted 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 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. 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, in certain circumstances, 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.

The current administration has delayed the implementation of certain regulations and signaled through formal and informal means that certain other income tax related regulations could be changed. The partnership audit regulations could be subject to revision, withdrawal or material adjustment, but the specifics of any such action cannot be reasonably predicted at this time.

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

Anhydrous Ammonia Event. On October 17, 2016, we experienced a release of anhydrous ammonia on our ammonia pipeline system near Tekamah, Nebraska. The release resulted in a fatality and other possible injuries. The National Transportation Safety Board is investigating the event. We are currently unable to estimate the full impact of this event. However, we believe the impact on our financial position and results of operations is not likely to be material as defined by the SEC.

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 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 $8,000 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.

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 14, 2018, we had 228,195,160 limited partner units outstanding that were owned by approximately 185,000 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.

The year-end closing sales price of our limited partner units was $75.63 on December 30, 2016 and $70.94 on December 29, 2017. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2016 and 2017 were as follows:

	2016			2017		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$72.00	$55.25	$ 0.8025	$81.77	$73.33	$ 0.8725
2nd	$77.45	$63.40	$ 0.8200	$78.00	$67.58	$ 0.8900
3rd	$77.10	$67.34	$ 0.8375	$72.40	$63.92	$ 0.9050
4th	$75.92	$64.25	$ 0.8550	$71.46	$63.55	$ 0.9200

* Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter.

We currently pay quarterly cash distributions of $0.92 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") and (ii) the Alerian MLP Index, which is a composite of the most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class. The graph assumes that $100 was invested in our limited partner units and each comparison index beginning on December 31, 2012 and that all distributions or dividends were reinvested on a quarterly basis.

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
Magellan Midstream Partners, L.P.	$100	$152	$205	$175	$205	$202
Alerian MLP Index	$100	$128	$134	$90	$107	$100
S&P 500	$100	$132	$151	$153	$171	$208

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 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 16 – 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, and we believe that investors benefit from having access to the same financial measures utilized by management. Operating profit, alternatively, includes depreciation and amortization expense and general and administrative (“G&A”) expense that management does not consider 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. Prior year numbers have been restated in accordance with Accounting Standards Update (“ASU”) 2017-07, Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (See Note 2 – Summary of Significant Accounting Policies – New Accounting Pronouncements under Item 8. Financial Statements and Supplementary Data of this report).

	Year Ended December 31,				
	2013	2014	2015	2016	2017
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenue	$1,188,452	$1,459,267	$1,544,746	$1,591,119	$1,731,775
Product sales revenue	744,669	878,974	629,836	599,602	758,206
Affiliate management fee revenue	14,609	22,111	13,871	14,689	17,680
Total revenue	1,947,730	2,360,352	2,188,453	2,205,410	2,507,661
Operating expenses	395,254	499,053	523,650	528,672	577,978
Cost of product sales	578,029	594,585	447,273	493,338	635,617
Subtotal	974,447	1,266,714	1,217,530	1,183,400	1,294,066
Earnings of non-controlled entities	6,275	19,394	66,483	78,696	120,994
Operating margin	980,722	1,286,108	1,284,013	1,262,096	1,415,060
Depreciation and amortization expense	142,230	161,741	166,812	178,142	196,630
G&A expense	131,920	147,203	149,948	147,165	165,717
Operating profit	706,572	977,164	967,253	936,789	1,052,713
Interest expense, net	118,206	121,519	143,177	165,410	193,718
Gain on sale of asset	—	—	—	—	(18,505)
Gain on exchange of interest in non-controlled entity	—	—	—	(28,144)	—
Other (income) expense[(a)]	1,516	11,506	2,618	(6,466)	4,139
Income before provision for income taxes	586,850	844,139	821,458	805,989	873,361
Provision for income taxes	4,613	4,620	2,336	3,218	3,830
Net income	$582,237	$839,519	$819,122	$802,771	$869,531
Basic net income per limited partner unit	$2.57	$3.69	$3.60	$3.52	$3.81
Diluted net income per limited partner unit	$2.56	$3.69	$3.59	$3.52	$3.81
Balance Sheets Data:					
Working capital (deficit)[(b)]	$(241,543)	$(133,488)	$(374,218)	$(111,262)	$(224,671)
Total assets	$4,803,307	$5,501,409	$6,041,567	$6,772,073	$7,394,375
Long-term debt, net	$2,417,811	$2,967,019	$3,189,287	$4,087,192	$4,273,518
Partners' capital	$1,647,442	$1,868,233	$2,021,736	$2,092,105	$2,129,653
Cash Distribution Data:					
Cash distributions declared per unit[(c)]	$2.18	$2.62	$3.01	$3.32	$3.59
Cash distributions paid per unit[(c)]	$2.10	$2.51	$2.92	$3.25	$3.52

	Year Ended December 31,				
	2013	2014	2015	2016	2017
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	$694,652	$871,492	$778,515	$723,588	$825,746
Crude oil	176,543	296,132	381,819	408,327	465,386
Marine storage	106,348	114,971	119,828	125,226	118,654
Allocated partnership depreciation costs[d]	3,179	3,513	3,851	4,955	5,274
Operating margin	$980,722	$1,286,108	$1,284,013	$1,262,096	$1,415,060
Adjusted EBITDA and distributable cash flow:					
Net income	$582,237	$839,519	$819,122	$802,771	$869,531
Interest expense, net	118,206	121,519	143,177	165,410	193,718
Depreciation and amortization	142,230	161,741	166,812	178,142	196,630
Equity-based incentive compensation[e]	11,823	12,471	6,461	4,982	6,766
Loss on sale and retirement of assets	7,835	7,223	7,871	11,190	13,370
Gain on sale of asset[f]	—	—	—	—	(18,505)
Gain on exchange of interest in non-controlled entity[h]	—	—	—	(28,144)	—
Commodity-related adjustments[g]	(339)	(56,288)	13,988	64,257	12,463
Cash distributions received from non-controlled entities in excess of (less than) earnings for the period	(409)	(8,724)	14,572	9,293	25,216
Other[i]	—	—	—	5,341	3,749
Adjusted EBITDA	861,583	1,077,461	1,172,003	1,213,242	1,302,938
Interest expense, net, excluding debt issuance cost amortization	(115,782)	(119,186)	(140,464)	(162,251)	(190,403)
Maintenance capital[j]	(76,081)	(77,806)	(88,685)	(103,507)	(91,163)
Distributable cash flow	$669,720	$880,469	$942,854	$947,484	$1,021,372
Operating Statistics:					
Refined products:					
Transportation revenue per barrel shipped	$1.313	$1.399	$1.439	$1.473	$1.495
Volume shipped (million barrels):					
Gasoline	239.7	256.1	268.1	275.4	295.5
Distillates	146.5	163.1	152.5	150.2	166.2
Aviation fuel	21.1	23.0	21.2	25.7	26.5
Liquefied petroleum gases	7.8	9.9	9.7	10.4	9.9
Total volume shipped	415.1	452.1	451.5	461.7	498.1
Crude oil:					
Magellan 100%-owned assets:					
Transportation revenue per barrel shipped	$0.880	$1.192	$1.118	$1.321	$1.348
Volume shipped (million barrels)	113.2	185.5	209.9	187.0	196.4
Crude oil terminal average utilization (million barrels per month)	12.3	12.2	13.1	15.0	15.3
Select joint venture pipelines:					
BridgeTex - volume shipped (million barrels)[k]	—	18.3	75.2	79.0	98.4

Saddlehorn - volume shipped (million barrels)[1]	—	—	—	5.2	19.0
Marine storage:					
Marine terminal average utilization (million barrels per month)	23.0	22.9	24.0	23.8	23.1

(a) Other (income) expense primarily includes the non-cash impact of the change in the differential between the current spot price and forward price on fair value hedges and non-service components of net periodic benefit costs.

(b) Working capital deficit at December 31, 2013, 2015 and 2017 included the current portion of long-term debt of approximately $250 million for each period.

(c) Cash distributions declared were determined based on DCF generated for each calendar year. Distributions were 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.

(d) 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.

(e) Because we intend to satisfy vesting of unit awards under our equity-based 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. However, equity-based compensation expense has been adjusted for cash payments associated with our equity-based incentive compensation plan, which primarily include tax withholdings.

(f) In September 2017, we recognized an $18.5 million gain in connection with the sale of an inactive terminal in Chicago, Illinois, which has been deducted from the calculation of DCF because it is not related to our ongoing 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.

(h) In February 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.

(i) In conjunction with the February 2016 Osage transaction, HFC agreed to make certain payments to us until HFC completes a connection to our El Paso terminal. We recorded a receivable in relation to this transaction, which was fully collected as of September 30, 2017. The purpose of these payments was to replace distributions we would have received had the Osage transaction not occurred and, therefore, these payments are included in our calculation of DCF.

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

(k) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us and began operations in September 2014.

(l) 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. Our three operating segments including the assets of our joint ventures include:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 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 storage facilities with an aggregate capacity of approximately 28 million barrels, of which 17 million are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

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, 2017.

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.

Demand for our services remains strong. In fact, we delivered record volumes on our refined products pipeline system during the year, with an 8% increase in shipments. This impressive growth was due to record demand for gasoline and diesel fuel in the markets we serve as well as the full-year benefit of our recently-built Little Rock pipeline, which began operations in mid-2016.

Our crude oil pipelines continue to provide important take-away capacity to deliver domestic crude oil to strategic locations in Cushing, Oklahoma and the Texas Gulf Coast region. We began operations in 2017 of our newly constructed condensate splitter in Corpus Christi, Texas, which is supported by a long-term customer commitment. Further, our marine terminals are in high demand as the industry seeks more infrastructure solutions to meet the growing need for storage and export capabilities.

The year 2017 was not without its challenges, especially in light of Hurricane Harvey which hit the Texas Gulf Coast during the third quarter, negatively impacting a number of our facilities. Overall, we made it through the storm well, with operations affected for a limited period of time due to the hard work of our dedicated employees, who in many cases were dealing with personal hardships of their own. We are very thankful for their service and diligence to restore our operations as soon and as safely as possible. Although a few tanks are still under repair at our Galena Park facility, the remainder of our impacted assets are back to full strength following the storm.

Growth Projects

Customer demand to utilize our Texas refined products pipeline system exceeds our current capacity. In response, we are building a new 135-mile pipeline segment from our East Houston terminal to Hearne, Texas. This expansion will provide us the ability to deliver nearly 50% more product originating from the Houston area to our Texas and

Midcontinent markets, beginning in mid-2019. We are pleased to meet the industry's need for more pipeline capacity serving the Dallas market and other important demand centers along our refined products pipeline system with an attractive investment supported by long-term commitments.

We increased the capacity of the BridgeTex pipeline during the year from 300,000 barrels per day (“bpd”) to 400,000 bpd to deliver more Permian Basin production to the Houston Gulf Coast. Due to increased demand for take-away capabilities from this region, we are increasing this pipeline system further to 440,000 bpd by early 2019.

We also launched a project to construct a 60-mile crude oil and condensate pipeline from the Delaware Basin to Crane, Texas, which essentially extends the reach of our Longhorn pipeline system and will provide our customers an additional outlet to move volume from this rapidly growing basin to the Houston Gulf Coast refining region. This project is driven by strong customer interest to source volumes directly to Longhorn from the Delaware Basin instead of routing the volumes through Midland. This new Delaware Basin pipeline, which is expected to be operational in mid-2019, strengthens the supply options to our Longhorn pipeline and serves as a logical next step in a broader strategy to expand our service offerings in the Permian Basin.

Significant progress has been made to build out our Seabrook Logistics joint venture, which provides an export solution for crude oil. The first phase of this facility became operational during 2017, with the second phase on-target for a mid-2018 start-up, including connectivity to our Houston crude oil distribution system.

To further expand our marine strategy, we announced plans to join forces with Valero Energy to invest in and expand the Pasadena marine terminal that is currently under construction in Texas. The initial phase of this new facility is expected to be operational in early 2019, with the second phase expected to come online in early 2020. Combined, our joint venture with Valero Energy is building 5 million barrels of storage and two ship docks at this facility, with the potential to double its size in the future.

Recent Developments

Cash Distribution. In January 2018, the board of directors of our general partner declared a quarterly cash distribution of $0.92 per unit for the period of October 1, 2017 through December 31, 2017. This quarterly cash distribution was paid on February 14, 2018 to unitholders of record on February 6, 2018. The total distribution paid on 228.2 million limited partner units outstanding was $209.9 million.

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 a non-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 and amortization 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 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, 2016 Compared to Year Ended December 31, 2017

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2016	2017	$ 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	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 and amortization 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 sale of asset	—	(18.5)	18.5	n/a
Gain on exchange of interest in non-controlled entity	(28.1)	—	(28.1)	(100)%
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:		
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 the total shipments for the BridgeTex pipeline, which is owned 50% by us.
(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 the current period 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 the current period 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, the current period 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 new 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 slightly lower utilization due to the timing of maintenance work and tanks damaged by Hurricane Harvey that are 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 new condensate splitter that began commercial operations in June 2017, less favorable product overages and more asset integrity spending during the current year; 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 sales revenue resulted primarily from our butane blending activities, transmix fractionation, crude oil marketing activities and the sale of tender deductions and product overages from our operations. We utilize futures contracts to hedge against changes in the price of petroleum products we expect to sell in future periods, as well as to hedge against changes in the price of butane we expect to purchase. See Note 13 –Derivative Financial Instruments in Item 8. Financial Statements and Supplementary Data for a discussion of our hedging strategies and how our use of futures contracts impacts our product margin and Other Items – Commodity Derivative Agreements below for more information about our futures contracts. Product margin increased $16.3 million primarily due to lower losses recognized in the current year on futures contracts, partially offset by lower margins on product sales from our butane blending activities. See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our futures contracts.

Earnings of non-controlled entities increased $42.3 million primarily due to higher earnings from BridgeTex Pipeline Company, LLC (“BridgeTex”) mainly attributable to incremental spot shipments (including spot shipments by us; see Note 4 – 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 Pipeline Company, LLC ("Saddlehorn"), which began operating during third quarter 2016.
Depreciation and amortization expense increased $18.6 million primarily due to commencement of depreciation of expansion capital projects recently 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 the current period, 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.
In 2017, we recognized an $18.5 million gain in connection with the sale of an inactive terminal in Chicago, Illinois. In 2016, we recognized a $28.1 million gain related to the transfer of our 50% membership interest in Osage Pipe Line Company, LLC ("Osage"). See Note 4 – Investments in Non-Controlled Entities in Item 8. Financial Statements and Supplementary Data of this report for more details regarding this transaction.
Other (income) expense was $10.6 million unfavorable in 2017 due to higher pension-related costs in the current period, 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.

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

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2015	2016	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$974.5	$1,002.4	$ 27.9	3 %
Crude oil	394.1	407.8	13.7	3 %
Marine storage	176.1	181.7	5.6	3 %
Intersegment eliminations	—	(0.8)	(0.8)	n/a
Total transportation and terminals revenue	1,544.7	1,591.1	46.4	3 %
Affiliate management fee revenue	13.9	14.7	0.8	6 %
Operating expenses:				
Refined products	376.3	380.4	(4.1)	(1)%
Crude oil	89.0	88.6	0.4	— %
Marine storage	62.2	65.5	(3.3)	(5)%
Intersegment eliminations	(3.9)	(5.8)	1.9	49 %
Total operating expenses	523.6	528.7	(5.1)	(1)%
Product margin:				
Product sales	629.8	599.6	(30.2)	(5)%
Cost of product sales	447.3	493.3	(46.0)	(10)%
Product margin	182.5	106.3	(76.2)	(42)%
Earnings of non-controlled entities	66.5	78.7	12.2	18 %
Operating margin	1,284.0	1,262.1	(21.9)	(2)%
Depreciation and amortization expense	166.8	178.1	(11.3)	(7)%
G&A expense	149.9	147.2	2.7	2 %
Operating profit	967.3	936.8	(30.5)	(3)%
Interest expense (net of interest income and interest capitalized)	143.2	165.4	(22.2)	(16)%
Gain on exchange of interest in non-controlled entity	—	(28.1)	28.1	n/a
Other (income) expense	2.7	(6.5)	9.2	n/a
Income before provision for income taxes	821.4	806.0	(15.4)	(2)%
Provision for income taxes	2.3	3.2	(0.9)	(39)%
Net income	$819.1	$802.8	$ (16.3)	(2)%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$1.439	$1.473		
Volume shipped (million barrels):				
Gasoline	268.1	275.4		
Distillates	152.5	150.2		
Aviation fuel	21.2	25.7		
Liquefied petroleum gases	9.7	10.4		
Total volume shipped	451.5	461.7		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$1.118	$1.321		
Volumes shipped (million barrels)	209.9	187.0		
Crude oil terminal average utilization (million barrels per month)	13.1	15.0		
Select joint venture pipelines:				

BridgeTex - volume shipped (million barrels)[a]	75.2	79.0
Saddlehorn - volume shipped (million barrels)[b]	—	5.2
Marine storage:		
Marine terminal average utilization (million barrels per month)	24.0	23.8

(a) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.
(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 $46.4 million, resulting from:

- an increase in refined products revenue of $27.9 million. Transportation revenue was favorably impacted by the mid-year 2015 tariff rate increase of 4.6% and the mid-year 2016 increase which averaged approximately 2.0% across all of our markets. Shipments increased 2% in 2016 primarily associated with additional volumes from growth projects, including our Little Rock pipeline extension which commenced commercial operations in July 2016, and increased demand for gasoline and aviation fuel. Additionally, revenue from storage services along our pipeline system increased due to new customer contracts;

- an increase in crude oil revenue of $13.7 million primarily due to higher average rates, as well as new storage contracts. Overall crude oil shipments declined and average rate per barrel increased due to fewer barrels moving on our lower-priced Houston distribution system tariff structure to their ultimate destination. Instead, customers utilized space available on our capacity lease for shipments from the BridgeTex pipeline; and

- an increase in marine storage revenue of $5.6 million primarily due to higher average rates from contract renewals and escalations. Total utilization decreased slightly due in part to timing of project work to convert tanks to crude oil service at our Galena Park, Texas terminal in 2016.

Affiliate management fee revenue increased $0.8 million primarily resulting from a one-time start-up fee received from Saddlehorn, which began operations in September 2016, partially offset by lower construction management fees received from our joint ventures and lower fees from Osage due to the transfer of our 50% membership interest in 2016.

Operating expenses increased $5.1 million, resulting from:

- an increase in refined products expenses of $4.1 million primarily resulting from rental costs for a pipeline segment we began leasing in third quarter 2016 in connection with our Little Rock pipeline, higher asset retirements and higher environmental accruals, partially offset by lower asset integrity spending due to timing of tank maintenance work;

- a decrease in crude oil expenses of $0.4 million as lower power costs and more favorable product overages (which reduce operating expenses) were primarily offset by increased personnel costs related to incremental headcount to support the crude oil segment; and

- an increase in marine storage expenses of $3.3 million primarily attributable to higher asset integrity spending in 2016.

Product margin decreased $76.2 million primarily due to lower margins from our butane blending activities as a result of lower realized sales prices and higher losses on futures contracts recognized in 2016. See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our futures contracts.

Earnings of non-controlled entities increased $12.2 million primarily attributable to increased earnings from BridgeTex due to higher shipments in 2016, as well as earnings from Saddlehorn, which began operating during third quarter 2016, and higher earnings from Double Eagle Pipeline LLC ("Double Eagle").

Depreciation and amortization expense increased $11.3 million in 2016 primarily due to expansion capital expenditures.

G&A expense decreased $2.7 million between periods primarily due to lower equity-based incentive compensation and lower employee bonus accruals.

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Interest expense, net of interest income and interest capitalized, increased $22.2 million in 2016 primarily due to higher outstanding debt and higher average interest rates on our debt, partially offset by higher capitalized interest. Our average outstanding debt increased from $3.3 billion in 2015 to $3.9 billion in 2016 primarily due to borrowings for expansion capital expenditures. Our weighted-average interest rate of 4.9% in 2016 was higher than the 4.7% rate incurred in 2015.

In 2016, we recognized a $28.1 million gain related to the transfer of our 50% membership interest in Osage. See Note 4 – Investments in Non-Controlled Entities in Item 8. Financial Statements and Supplementary Data of this report for more details regarding this transaction.

Other (income) expense was $9.2 million favorable due to a more favorable non-cash adjustment in 2016 for the change in the differential between the then-current spot price and forward price on fair value hedges. Additionally, other (income) expense included a break-up fee in 2016 related to a potential acquisition.

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, 2015, 2016 and 2017 to net income, which is the nearest comparable GAAP financial measure, is as follows (in millions):

	Year Ended December 31,		
	2015	2016	2017
Net income	$819.1	$802.8	$869.5
Interest expense, net	143.2	165.4	193.7
Depreciation and amortization	166.8	178.1	196.6
Equity-based incentive compensation(1)	6.5	5.0	6.8
Loss on sale and retirement of assets	7.9	11.2	13.4
Gain on sale of asset(2)	—	—	(18.5)
Gain on exchange of interest in non-controlled entity(3)	—	(28.1)	—
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions(5)	(47.8)	21.8	37.6
Derivative gains (losses) recognized in previous periods associated with product sales completed in the period(5)	96.1	45.2	(25.5)
Inventory valuation adjustments(6)	(34.3)	(2.8)	0.4
Total commodity-related adjustments	14.0	64.2	12.5
Cash distributions received from non-controlled entities in excess of earnings(7)	14.5	9.3	25.2
Other(4)	—	5.3	3.7
Adjusted EBITDA	1,172.0	1,213.2	1,302.9
Interest expense, net, excluding debt issuance cost amortization	(140.5)	(162.2)	(190.4)
Maintenance capital(8)	(88.7)	(103.5)	(91.1)
DCF	$942.8	$947.5	$1,021.4

(1) Because we intend to satisfy vesting of unit awards under our equity-based 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 equity-based compensation adjustment for the years ended December 31, 2015, 2016 and 2017 was $24.3 million, $19.4 million and $20.6 million, respectively. However, the figures above include adjustments of $17.8 million, $14.4 million and $13.9 million, respectively, for cash payments associated with our equity-based incentive compensation plan, which primarily include tax withholdings.

(2) In September 2017, we recognized an $18.5 million gain in connection with the sale of an inactive terminal in Chicago, Illinois, which has been deducted from the calculation of DCF because it is not related to our ongoing operations.

(3) In February 2016, we transferred our 50% membership interest in 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) In conjunction with the February 2016 Osage transaction, HFC agreed to make certain payments to us until HFC completes a connection to our El Paso terminal. We recorded a receivable in relation to this transaction, which was fully collected as of September 30, 2017. The purpose of these payments was to replace distributions we would have received had the Osage transaction not occurred and, therefore, these payments are included in our calculation of DCF.

(5) 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 earnings. In addition, we have

designated certain derivatives we use to hedge our crude oil tank bottoms as fair value hedges and the change in the differential between the current spot price and forward price on these hedges is recognized currently in earnings. We exclude the net impact of both of these adjustments 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.

(6) 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 subsequent periods when we physically sell or purchase the related products, we adjust DCF for the valuation adjustments previously recognized.

(7) The cash distributions received from non-controlled entities in excess of earnings only include cash flows from ongoing operations of those entities. See Note 4 – Investments in Non-Controlled Entities in Item 1 of Part I of this report for more detailed information.

(8) Maintenance capital expenditures maintain our existing assets and do not generate incremental DCF (i.e. 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 $1,069.7 million, $964.0 million and $1,108.7 million for the years ended December 31, 2015, 2016 and 2017, respectively. The $144.7 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. The $105.7 million decrease from 2015 to 2016 was due to changes in our working capital, adjustments to non-cash items and lower net income as previously described.

Investing Activities. Net cash used by investing activities for the years ended December 31, 2015, 2016 and 2017 was $810.8 million, $857.4 million and $570.6 million, respectively. During 2017, we incurred $572.7 million for 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, which we account for as investments in non-controlled entities. During 2016, we incurred $653.5 million for 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. During 2015, we incurred $623.3 million for capital expenditures, which included $88.7 million for maintenance capital and $534.6 million for expansion capital. Also during 2015, we acquired a refined products terminal in the Atlanta, Georgia market for $54.7 million and we contributed capital of $152.5 million in conjunction with our joint venture capital projects.

Financing Activities. Net cash used by financing activities for the years ended December 31, 2015, 2016 and 2017 was $247.3 million, $120.7 million and $376.7 million, respectively. 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, the cumulative amounts of the 2014 equity-based incentive compensation awards were settled by issuing 216,679 limited partner units and distributing those units to the long-term incentive plan ("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. In connection with certain of the borrowings under long-term notes, we paid $19.3 million in settlement of associated interest rate swap agreements. Also, in February 2016, the cumulative amounts of the January 2013 equity-based incentive compensation awards were settled by issuing 350,552 limited partner units to the LTIP participants, resulting in payments of associated tax withholdings of $14.4 million. During 2015, we paid cash distributions of $662.9 million to our unitholders. Additionally, we received net proceeds of $499.6 million from borrowings under long-term notes, which were used in part to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital. In connection with the borrowings under long-term notes, we paid $42.9 million in settlement of associated interest rate swap agreements. Also, in January 2015, the cumulative amounts of the January 2012 equity-based incentive compensation awards were settled by issuing 354,529 limited partner units to the LTIP participants, resulting in payments of associated tax withholdings of $17.8 million.

The quarterly distribution amount related to fourth quarter 2017 earnings was $0.92 per unit, which was paid in February 2018. If we are able to meet management's targeted distribution growth of 8% during 2018 and the number of outstanding limited partner units remains at 228.2 million, total cash distributions of approximately $885 million will be paid to our unitholders related to 2018 earnings. Management believes we will have sufficient DCF to fund these distributions.

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 2017, our maintenance capital spending was $91.2 million. For 2018, we expect to spend approximately $90 million on maintenance capital.

During 2017, we spent more than $540 million on organic growth construction projects. Based on the progress of expansion projects already underway, we expect to spend approximately $900 million for expansion capital during 2018, with an additional $375 million in 2019 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 12 – Debt in Item 8. Financial Statements and Supplementary Data of this report for detail of our borrowings and debt outstanding at December 31, 2016 and 2017). 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, 2017 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$4,550.0	$ 250.0	$550.0	$ 550.0	$3,200.0
Interest obligations(1)	3,282.4	217.3	361.8	300.5	2,402.8
Operating lease obligations	262.5	34.5	58.4	53.6	116.0
Pension and postretirement medical obligations(2)	111.9	28.7	53.7	20.4	9.1
Purchase commitments:					
Product purchase commitments(3)	127.5	100.6	26.9	—	—
Utility purchase commitments	22.8	12.2	9.3	1.2	0.1
Derivative instruments(4)	—	—	—	—	—
Equity-based incentive awards(5)	37.4	19.9	17.5	—	—
Capital project purchase obligations	147.2	141.5	5.7	—	—
Maintenance obligations	94.1	94.0	0.1	—	—
Other	8.9	4.6	2.7	1.6	—
Total	$8,644.7	$ 903.3	$1,086.1	$ 927.3	$5,728.0

(1) At December 31, 2017, 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) Represents the projected benefit obligation of our pension and postretirement medical plans less the fair value of plan assets.

(3) Includes product purchase commitments for which the price provisions are indexed based on the date of delivery. We have estimated the value of these commitments using the related index price curve as of December 31, 2017. Also, we have excluded certain product purchase agreements for which there is no specified or minimum quantity.

(4) As of December 31, 2017, we had entered into exchange-traded futures contracts representing 4.4 million barrels of petroleum products that we expect to sell in the future and 1.5 million barrels of butane we expect to purchase in the future. At December 31, 2017, we had recorded a net liability of $26.1 million and made margin deposits of $36.7 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.

(5) Settlements of our equity-based incentive awards will differ from these reported amounts primarily due to differences between 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 2017, we expect to increase virtually all of our refined products pipeline rates by approximately 4.4% on July 1, 2018. 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 between 2% and 3% on average in July 2018.

Longhorn Pipeline Contracts Renewal. Our current contracts for the Longhorn pipeline expire on September 30, 2018. We are in active discussions with shippers regarding potential new rates and terms upon re-contracting. Although we remain confident that demand for space on the Longhorn pipeline is strong, the pricing environment for term commitments on crude oil pipelines originating from the Permian Basin is very competitive. As a result, we assume the tariff rates for the Longhorn pipeline will be lower upon re-contracting in the fourth quarter of 2018.

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, 2017, 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, fractionation and certain crude oil inventory 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, and the change in fair value of contracts that hedge future purchases recorded to cost of product sales or operating expense.

For further information regarding the quantities of refined products and crude oil hedged at December 31, 2017 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, 2015				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Results of Operations
Gains (losses) recorded on open futures contracts during the period	$41.3	$ (5.2)	$ 3.1	$ 1.0	$ 40.2
Gains (losses) recognized on settled futures contracts during the period	27.1	(3.8)	8.7	—	32.0
Net impact of futures contracts	$68.4	$ (9.0)	$ 11.8	$ 1.0	$ 72.2

	Year Ended December 31, 2016				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Results of Operations
Gains (losses) recorded on open futures contracts during the period	$(30.2)	$ 6.1	$ (3.6)	$ 5.2	$ (22.5)
	(8.4)	4.9	(1.4)	—	(4.9)

Gains (losses) recognized on settled futures contracts during the period					
Net impact of futures contracts	$(38.6)	$ 11.0	$ (5.0)	$ 5.2	$ (27.4)

	Year Ended December 31, 2017				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Results of Operations
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)

Senior Management Changes in 2017. Melanie Little was elected by our general partner's board of directors as Senior Vice President, Operations, effective July 1, 2017. Ms. Little has 16 years of service with us and has held Vice President level positions for the last six years in Crude Oil, Commercial and Operations.

Related Party Transactions. See Note 11 – 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 and Postretirement Obligations

We sponsor two union pension plans covering certain employees ("USW plan" and "IUOE plan"), a pension plan for all non-union employees ("Salaried plan") and a postretirement benefit plan for certain 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, expected rate of compensation increase and the assumed health care cost trend rate. 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	$3,893	$4,875	$(31,919)	$38,221
Expected long-term rate of return on plan assets	$(892)	$2,943	$—	$—
Rate of compensation increase	$3,450	$(3,135)	$15,603	$(15,803)
Other postretirement benefits:				
Discount rate	$(134)	$172	$(1,495)	$1,942
Assumed health care cost trend rate	$67	$(62)	$411	$(382)

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	$(1,415)	$2,253
Rate of compensation increase	$3,133	$(2,689)

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The discount rate directly affects the measurement of the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rate is to determine the amount, if invested at the December 31st 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. We base the assumed health care cost trend rates on national trend rates adjusted for our actual historical claims experience and plan design. An increase in this rate causes the other postretirement benefit obligation and expense to increase.

Impairment of Long-Lived Assets.

Long-lived assets, including fixed assets, investments in non-controlled entities, goodwill 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.

Determination as to whether and how much an asset is 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.

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.

We have the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test.

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, 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 calculated that the fair value of each of our reporting units was greater than its carrying amount.

An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and calculations is not practicable, given the broad range of our assets and the number of assumptions involved in the estimates. Favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an increase in impairments recognized.

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 since the last annual meeting of the remediation project managers, any changes in the site situation remediation, 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, 2015 were as follows (in millions):

Balance 12/31/15	2016 Accruals	Expenditures	Balance 12/31/16	2017 Accruals	Expenditures	Balance 12/31/17
$31.4	$8.4	$(15.8)	$24.0	$12.8	$(17.5)	$19.3

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.

During 2016, we accrued $8.4 million of environmental liabilities. Of this amount, $8.6 million related to product releases that occurred during 2016, and the remaining accrual adjustments of $(0.2) million related to historical releases. At December 31, 2016, we had recognized $4.1 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,” “schedule 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 projected, forecasted, estimated or budgeted amounts we have discussed in this report:

- overall demand for refined products, crude oil, liquefied petroleum gases and ammonia in the U.S.;
- price fluctuations for refined products, crude oil, liquefied petroleum gases and ammonia 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, the U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants, ammonia production facilities 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 or to complete identified expansion projects on time and at projected costs;

- 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 ammonia, 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, 2017, we had commitments under forward purchase and sale contracts as follows (in millions):

	Total	< 1 Year	1 – 3 Years
Forward purchase contracts – notional value	$127.5	$100.6	$26.9
Forward purchase contracts – barrels	2.8	2.1	0.7
Forward sales contracts – notional value	$55.3	$55.0	$0.3
Forward sales contracts – barrels	0.7	0.7	< 0.1

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 4.4 million barrels of petroleum products we expect to sell and 1.5 million barrels of butane we expect to purchase, was a net liability of $25.9 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 $44.0 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 $15.0 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.

We entered into $100.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2018. The fair value of these contracts at December 31, 2017 was a net asset of $12.2 million. 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 $2.1 million. A 0.125% increase in interest rates would result in an increase of the fair value of this asset of approximately $2.0 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, 2017. 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, 2017, 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, 2017. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2017, 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, 2017 and 2016, and 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, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Partnership at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework) and our report dated February 16, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 1999.
Tulsa, Oklahoma
February 16, 2018

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, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Magellan Midstream Partners, L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, 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, 2017 and 2016, and 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, 2017, and the related notes and our report dated February 16, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's 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 16, 2018

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

	Year Ended December 31,		
	2015	2016	2017
Transportation and terminals revenue	$1,544,746	$1,591,119	$1,731,775
Product sales revenue	629,836	599,602	758,206
Affiliate management fee revenue	13,871	14,689	17,680
Total revenue	2,188,453	2,205,410	2,507,661
Costs and expenses:			
Operating	523,650	528,672	577,978
Cost of product sales	447,273	493,338	635,617
Depreciation and amortization	166,812	178,142	196,630
General and administrative	149,948	147,165	165,717
Total costs and expenses	1,287,683	1,347,317	1,575,942
Earnings of non-controlled entities	66,483	78,696	120,994
Operating profit	967,253	936,789	1,052,713
Interest expense	158,895	194,187	210,698
Interest capitalized	(14,442)	(27,375)	(15,565)
Interest income	(1,276)	(1,402)	(1,415)
Gain on sale of asset	—	—	(18,505)
Gain on exchange of interest in non-controlled entity	—	(28,144)	—
Other (income) expense	2,618	(6,466)	4,139
Income before provision for income taxes	821,458	805,989	873,361
Provision for income taxes	2,336	3,218	3,830
Net income	$819,122	$802,771	$869,531
Basic net income per limited partner unit	$3.60	$3.52	$3.81
Diluted net income per limited partner unit	$3.59	$3.52	$3.81
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	227,550	227,926	228,176
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	227,888	228,057	228,338

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2015	2016	2017
Net income	$819,122	$802,771	$869,531
Other comprehensive loss:			
Derivative activity:			
Net loss on cash flow hedges	(14,904)	(6,699)	(1,937)
Reclassification of net loss (gain) on cash flow hedges to income	1,365	2,049	2,958
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial loss	(8,359)	(2,452)	(46,008)
Plan amendment	3,610	—	—
Amortization of prior service credit	(3,713)	(3,516)	(181)
Amortization of actuarial loss	7,191	5,525	6,371
Settlement cost	—	202	2,460
Total other comprehensive loss	(14,810)	(4,891)	(36,337)
Comprehensive income	$804,312	$797,880	$833,194

See notes to consolidated financial statements.

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

	December 31, 2016	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$14,701	$176,068
Trade accounts receivable	105,689	138,779
Other accounts receivable	25,761	14,561
Inventory	134,378	182,345
Energy commodity derivatives deposits	49,899	36,690
Other current assets	39,966	63,396
Total current assets	370,394	611,839
Property, plant and equipment	6,783,737	7,235,468
Less: accumulated depreciation	1,507,996	1,682,633
Net property, plant and equipment	5,275,741	5,552,835
Investments in non-controlled entities	931,255	1,082,511
Long-term receivables	23,870	27,676
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $2,136 and $1,389 at December 31, 2016 and 2017, respectively)	51,976	52,764
Other noncurrent assets	65,577	13,490
Total assets	$6,772,073	$7,394,375
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$77,248	$104,852
Accrued payroll and benefits	45,690	56,261
Accrued interest payable	65,643	70,657
Accrued taxes other than income	50,166	51,343
Environmental liabilities	10,249	6,235
Deferred revenue	101,891	117,795
Accrued product liabilities	51,600	96,159
Energy commodity derivatives contracts, net	30,738	25,694
Current portion of long-term debt, net	—	250,974
Other current liabilities	48,431	56,540
Total current liabilities	481,656	836,510
Long-term debt, net	4,087,192	4,273,518
Long-term pension and benefits	71,461	111,305
Other noncurrent liabilities	25,868	30,350
Environmental liabilities	13,791	13,039
Commitments and contingencies		
Partners' capital:		
Limited partner unitholders (227,784 units and 228,025 units outstanding at December 31, 2016 and 2017, respectively)	2,193,346	2,267,231
Accumulated other comprehensive loss	(101,241)	(137,578)
Total partners' capital	2,092,105	2,129,653

Total liabilities and partners’ capital	$6,772,073	$7,394,375

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2015	2016	2017
Operating Activities:			
Net income	$819,122	$802,771	$869,531
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	166,812	178,142	196,630
Loss (gain) on sale and retirement of assets	7,871	11,190	(5,135)
Earnings of non-controlled entities	(66,483)	(78,696)	(120,994)
Distributions of investments in non-controlled entities	66,285	78,723	123,660
Equity-based incentive compensation expense	24,245	19,358	20,641
Settlement cost, amortization of prior service credit and actuarial loss	3,478	2,211	8,650
Gain on exchange of interest in non-controlled entity	—	(28,144)	—
Changes in components of operating assets and liabilities (Note 3)	48,362	(21,515)	15,695
Net cash provided by operating activities	1,069,692	964,040	1,108,678
Investing Activities:			
Additions to property, plant and equipment, net(1)	(621,151)	(674,159)	(558,669)
Proceeds from sale and disposition of assets	3,371	7,552	44,392
Acquisition of business	(54,678)	—	—
Investments in non-controlled entities	(152,466)	(200,023)	(134,828)
Distributions in excess of earnings of non-controlled entities	14,155	9,264	78,482
Net cash used by investing activities	(810,769)	(857,366)	(570,623)
Financing Activities:			
Distributions paid	(662,948)	(739,157)	(803,216)
Net commercial paper repayments	(16,981)	(229,975)	(49,986)
Borrowings under long-term notes	499,589	1,142,997	496,705
Payments on notes	—	(250,000)	—
Debt placement costs	(6,223)	(10,906)	(6,316)
Net payment on financial derivatives	(42,908)	(19,287)	—
Payments associated with settlement of equity-based incentive compensation	(17,784)	(14,376)	(13,875)
Net cash used by financing activities	(247,255)	(120,704)	(376,688)
Change in cash and cash equivalents	11,668	(14,030)	161,367
Cash and cash equivalents at beginning of period	17,063	28,731	14,701
Cash and cash equivalents at end of period	$28,731	$14,701	$176,068
Supplemental non-cash investing and financing activities:			
Contribution of property, plant and equipment to a non-controlled entity	$13,252	$—	$97,638
Issuance of limited partner units in settlement of equity-based incentive plan awards	$8,045	$7,289	$1,669
(1) Additions to property, plant and equipment	$(623,289)	$(653,528)	$(572,744)
Changes in accounts payable and other current liabilities related to capital expenditures	2,138	(20,631)	14,075
Additions to property, plant and equipment, net	$(621,151)	$(674,159)	$(558,669)

See notes to consolidated financial statements.

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

	Limited Partners	Accumulated Other Comprehensive Loss	Total Partners' Capital
Balance, January 1, 2015	$1,949,773	$(81,540)	$1,868,233
Comprehensive income:			
Net income	819,122	—	819,122
Total other comprehensive loss	—	(14,810)	(14,810)
Total comprehensive income (loss)	819,122	(14,810)	804,312
Distributions	(662,948)	—	(662,948)
Equity-based incentive compensation expense	22,248	—	22,248
Issuance of limited partner units in settlement of equity-based incentive plan awards	8,045	—	8,045
Payments associated with settlement of equity-based incentive compensation	(17,784)	—	(17,784)
Other	(370)	—	(370)
Balance, December 31, 2015	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

See notes to consolidated financial statements.

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, 2017, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,700-mile refined products pipeline system with 53 terminals as well as 26 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 storage facilities with an aggregate capacity of approximately 28 million barrels, of which approximately 17 million are used for contract storage; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

Description of Products

Terminology common in our industry includes the following terms, which describe products that we transport, store and distribute through our 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 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 and condensate are used as feedstocks by refineries and petrochemical facilities;

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

- ammonia is primarily used as a nitrogen fertilizer.

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

Except for ammonia, 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.

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, 2016 and 2017, we believed our credit risk relative to these funds was minimal.

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.

Revenue Recognition. Revenue is recognized based on contracts or other persuasive evidence of an arrangement with the customer that includes fixed or determinable prices in which collectability is reasonably assured. We recognize revenue net of all amounts charged to our customers for excise taxes.

We recognize pipeline transportation revenue for crude oil shipments when our customers' product arrives at the customer-designated destination. For shipments of refined products and ammonia 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 agreements that require counterparties to ship a minimum volume over an agreed-upon period. Revenue pursuant to such agreements is recognized at the earlier of when the volume is shipped or when the counterparty's ability to meet the minimum volume commitment has expired.

The tariffs we charge for our pipeline transportation systems are primarily regulated by the Federal Energy Regulatory Commission (“FERC”); however, certain tariffs are regulated by the Surface Transportation Board or state regulatory authorities. Generally, our tariffs include provisions that 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 these product quantities as tender deductions. We receive tender deductions from our customers as consideration for

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

product shortages during the transportation of their refined products or crude oil within our pipeline systems. Our customers are guaranteed delivery of the amount of their injected volumes, net of tender deductions, irrespective of what our actual product shortages may be during the delivery process. Tender deduction revenue is recognized as transportation and terminals revenue when the transportation barrels are received and is recorded at the fair value of the product received.

We recognize tank storage, pipeline capacity leases, terminalling, throughput, ethanol loading and unloading services, laboratory testing, data services, pipeline operation fees and other miscellaneous service-related revenue upon completion of the rendered services. Product sales revenue is recognized when the customer assumes the risks and rewards of ownership. We recognize injection service fees associated with additives upon injection to the customer's product, which occurs at the time we deliver the product to our customers.

Deferred Transportation Revenue and Costs. Generally, we invoice customers on our refined products pipeline 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 deferred liability. The value of this liability is calculated as the total of the volume of each product type, for each pipeline region, multiplied by the average tariff rate for that product type for the most recent month invoiced to our customers. We use the most recent month's average tariff rate because the product in our pipeline system generally turns over every month. Additionally, at each period end, we defer the direct costs we have incurred associated with these in-transit products, until delivery occurs, as a deferred asset. These direct costs are estimated based on our average per-barrel direct delivery cost for the current year 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 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 deferred revenues and costs are determined using judgments and assumptions that management considers reasonable.

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 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.

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

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.

Index of Additional Significant Accounting Policies

Investments in Non-Controlled Entities	Note 4 – Investments in Non-Controlled Entities
Inventory	Note 6 – Inventory
Property, Plant and Equipment	Note 8 – Property, Plant and Equipment
Goodwill and Other Intangible Assets	Note 8 – Property, Plant and Equipment
Impairment of Long-Lived Assets	Note 8 – Property, Plant and Equipment
Pension and Postretirement Medical and Life Benefit Obligations	Note 10 – Employee Benefit Plans
Derivative Financial Instruments	Note 13 – Derivative Financial Instruments
Equity-Based Incentive Compensation	Note 15 – Long-Term Incentive Plan
Contingencies and Environmental	Note 17 – Commitments and Contingencies

New Accounting Pronouncements

In August 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“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 plan to early adopt the new standard on January 1, 2018. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

In March 2017, the FASB issued ASU 2017-07, Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This ASU requires companies that offer postretirement benefits to present the service cost in the same line item with other employee compensation costs. Other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. Additionally, only the service cost component will be eligible for capitalization when applicable. Public companies must comply with the new requirements under ASU 2017-07 for fiscal years that start after December 15, 2017, and the amendments must be applied retrospectively except for the capitalization change, which should be applied prospectively. Early adoption is allowed, and we elected to adopt ASU 2017-07 as of January 1, 2017. Prior to adoption, we expensed all components of pension expense through salaries and wages, which impacted operating income. We are now recording only the service component of pension expense to salaries and wages, with the remainder of the expense being recorded to other income and expense below operating profit. Comparative prior periods have been restated for this change. The changes were not material to our financial statements.

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

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 makes eight targeted changes to how cash receipts and cash payments are presented and classified in the statement of cash flows. Current GAAP is either unclear or does not include specific guidance on these eight issues. This ASU is effective for fiscal years beginning after December 15, 2017. We do not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). This ASU requires lessees to recognize a right of use asset and lease liability on the balance sheets 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. We are currently in the process of evaluating the impact this new standard will have on our financial statements.

In July 2015, the FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory. Prior to this update, reporting entities were required to measure inventory at the lower of cost or market. Market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. Under this update, inventory is to be measured at the lower of cost or net realizable value, which is defined as the estimated selling price in the ordinary course of business, less reasonable predictable costs of completion, disposal and transportation. This ASU became effective for fiscal years beginning after December 15, 2016 and interim periods within those fiscal years. We adopted this standard on January 1, 2017, and it did not have a material impact on our results of operations, financial position or cash flows as we have historically measured our inventory at the lower of cost or net realizable value.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. 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. We will adopt this ASU as required on January 1, 2018, using the modified retrospective method of adoption. The primary impact to the financial statements will be the addition of the new disclosure requirements, as we do not expect material changes to individual line items in the consolidated financial statements.

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

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2015	2016	2017
Trade accounts receivable and other accounts receivable	$3,664	$(31,107)	$(25,639)
Inventory	26,894	(3,510)	(47,967)
Energy commodity derivatives contracts, net of derivatives deposits	(606)	(692)	8,556
Accounts payable	4,107	(4,423)	8,954
Accrued payroll and benefits	3,466	(6,074)	10,596
Accrued interest payable	5,323	14,347	5,014
Accrued taxes other than income	3,699	(1,421)	1,177
Deferred revenue	10,485	20,264	15,904
Accrued product liabilities	(13,016)	20,261	44,559
Current and noncurrent environmental liabilities	(4,904)	(7,398)	(4,766)
Other current and noncurrent assets and liabilities	9,250	(21,762)	(693)
Total	$48,362	$(21,515)	$15,695

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, 2015, 2016 and 2017, the long-term pension and benefits liability was increased by $4.7 million, $2.5 million and $46.0 million, respectively, resulting in a corresponding increase in accumulated other comprehensive loss (“AOCL”).

4. 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 $61.3 million and $59.7 million at December 31, 2016 and 2017, respectively. The amount of unamortized excess investment is primarily related to our investment in BridgeTex Pipeline Company, LLC. 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 2015, 2016 and 2017.

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

Our investments in non-controlled entities at December 31, 2017 were comprised of:

Entity	Ownership Interest
BridgeTex Pipeline Company, LLC (“BridgeTex”)	50%
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%

MVP was formed in September 2017 to construct and develop a refined products marine storage facility along the Houston Ship Channel in Pasadena, Texas. We own a 50% equity interest in MVP, with an affiliate of Valero Energy Corporation (“Valero”) owning the other 50% interest. We serve as construction manager and will serve as operator of the MVP facility. The initial phase of this facility is expected to be operational in early 2019, with the next phase of the project being completed in 2020. Upon formation of MVP, we contributed $97.6 million of property, plant and equipment (“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 in excess of earnings of non-controlled entities on our consolidated statements of cash flows.

We receive fees for management services from BridgeTex, HoustonLink, MVP, Powder Springs, Saddlehorn, Texas Frontera and the pipeline activities of Seabrook, 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 $1.3 million, $4.2 million and $3.6 million, respectively, for the years ended December 31, 2015, 2016 and 2017.

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

	Year Ended December 31,		
	2015	2016	2017
Transportation and terminals revenue:			
BridgeTex, capacity lease	$34.6	$35.5	$36.1
Double Eagle, throughput revenue	$3.4	$3.3	$4.7
Saddlehorn, storage revenue	$—	$0.7	$2.1

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

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

	December 31, 2016			December 31, 2017		
	Trade Accounts Receivable	Other Accounts Receivable	Other Accounts Payable	Trade Accounts Receivable	Other Accounts Receivable	Other Accounts Payable
Double Eagle	$ 0.3	$ —	$ —	$ 0.5	$ —	$ —
HoustonLink	$ —	$ —	$ —	$ —	$ —	$ 0.1
MVP	$ —	$ —	$ —	$ —	$ 0.4	$ —
Powder Springs	$ —	$ —	$ —	$ —	$ 0.9	$ —
Saddlehorn	$ —	$ 0.1	$ —	$ —	$ 0.1	$ —
Seabrook	$ —	$ —	$ —	$ —	$ 0.2	$ —

In addition to the transactions noted above, we incurred charges of $14.5 million for transportation of crude oil at published spot tariff rates on the BridgeTex pipeline for the year ended December 31, 2017. We recorded these charges as cost of product sales in our consolidated statements of income. We also purchased inventory from BridgeTex valued at $6.7 million during 2017.

In January 2017, we entered into an agreement to guarantee our 50% pro rata share, up to $50.0 million, of obligations under Powder Springs' credit facility. As of December 31, 2017, we had recognized a $0.8 million other current liability and a corresponding increase in our investment in non-controlled entities on our consolidated balance sheets to reflect the fair value of this guarantee.

In February 2016, we transferred a 50% membership interest in Osage Pipe Line Company, LLC ("Osage") to an affiliate of HollyFrontier Corporation. In conjunction with this transaction, we entered into several commercial agreements with affiliates of HollyFrontier Corporation, which we recorded at that time as a $43.7 million intangible asset and an $8.3 million other receivable on our consolidated balance sheets. The intangible asset will be amortized over the 20-year life of the contracts received. We recognized a $28.1 million non-cash gain in 2016 in relation to this transaction.

The financial results from MVP and Texas Frontera are included in our marine storage segment, the financial results from BridgeTex, Double Eagle, HoustonLink, Osage, Saddlehorn and Seabrook are included in our crude oil segment and the financial results from Powder Springs are included in our refined products segment, each as earnings of non-controlled entities.

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

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

Investments at December 31, 2016	$931,255
Additional investment[1]	232,404
Earnings of non-controlled entities:	
Proportionate share of earnings	123,373
Amortization of excess investment and capitalized interest	(2,379)
Earnings of non-controlled entities	120,994
Less:	
Distributions of earnings from investments in non-controlled entities	123,660
Distributions in excess of earnings of non-controlled entities[2]	78,482
Investments at December 31, 2017	$1,082,511

(1) Includes our $97.6 million contribution of PP&E to MVP.

(2) Includes the $48.8 million distribution to us from MVP as reimbursement for the PP&E we contributed, as well as an additional distribution of $6.2 million from BridgeTex that is not related to the ongoing operations of non-controlled entities.

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

	December 31,	
	2016	2017
Current assets	$208,901	$229,342
Noncurrent assets	1,714,920	2,057,892
Total assets	$1,923,821	$2,287,234
Current liabilities	$111,164	$122,198
Noncurrent liabilities	27,022	74,533
Total liabilities	$138,186	$196,731
Equity	$1,785,635	$2,090,503

	Year Ended December 31,		
	2015	2016	2017
Revenue	$246,841	$279,180	$419,214
Net income	$138,457	$164,684	$256,423

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

5. Business Combinations

2015 Business Combination.

On May 1, 2015, we acquired a refined products terminal in Atlanta, Georgia for net cash consideration of $54.7 million. As this acquired business is not significant to our consolidated operating results and financial position, pro forma financial information and the purchase price allocation of acquired assets and liabilities have not been presented. The results of the acquired operations subsequent to the acquisition date have been included in the accompanying consolidated financial statements and in the tables below in our refined products operating segment.

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, 2016 and 2017 was as follows (in thousands):

	December 31,	
	2016	2017
Refined products	$54,285	$73,845
Liquefied petroleum gases	24,868	45,553
Transmix	28,319	33,319
Crude oil	20,839	23,763
Additives	6,067	5,865
Total inventory	$134,378	$182,345

7. Product Sales Revenue
The amounts reported as product sales revenue on our consolidated statements of income include revenue from the physical sale of petroleum products and mark-to-market adjustments from exchange-based futures contracts. See Note 13 – Derivative Financial Instruments for a discussion of our commodity hedging strategies and how our futures contracts impact product sales revenue.

For the years ended December 31, 2015, 2016 and 2017, product sales revenue included the following (in thousands):

	Year Ended December 31,		
	2015	2016	2017
Physical sale of petroleum products	$561,410	$638,186	$814,544
Change in value of futures contracts	68,426	(38,584)	(56,338)
Total product sales revenue	$629,836	$599,602	$758,206

8. 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

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

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 was 4.7%, 4.9% and 4.8% for the years ended December 31, 2015, 2016 and 2017, respectively.

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

	December 31, 2016	2017	Estimated Depreciable Lives
Construction work-in-progress	$ 500,208	$ 389,414	
Land and rights-of-way	339,561	303,797	
Buildings	101,065	114,899	10 to 56 years
Storage tanks	1,829,223	1,897,046	10 to 40 years
Pipeline and station equipment	2,457,429	2,581,950	10 to 69 years
Processing equipment	1,350,032	1,703,478	3 to 56 years
Other	206,219	244,884	3 to 53 years
Property, Plant and Equipment, Gross	$ 6,783,737	$ 7,235,468	

Other includes total interest capitalized on construction in progress as of December 31, 2016 and 2017 of $43.1 million and $57.3 million, respectively. Depreciation expense for the years ended December 31, 2015, 2016 and 2017 was $164.1 million, $176.7 million and $196.3 million, respectively.

Goodwill and Other Intangibles

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.

We amortize other intangible assets with finite lives over their estimated useful lives of six years up to 30 years. The weighted-average asset life of our other intangible assets at December 31, 2017 was approximately 21 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. During the years ended December 31, 2015, 2016 and 2017, amortization of other intangible assets was $2.7 million, $1.4 million and $0.4 million, respectively.

Impairment of Long-Lived Assets

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.

For purposes of performing the impairment test for goodwill, our reporting units are refined products, crude oil and marine storage. In 2015 and 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, 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.

During the years ended December 31, 2015, 2016 and 2017, no material impairments of long-lived assets were recorded.

9. Major Customers and Concentration of Risks

Major Customers. No customer accounted for more than 10% of our consolidated revenues during 2015, 2016 or 2017.

Concentration of Risks. We transport, store and distribute refined products for refiners, 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, 2017, we had 1,802 employees, 940 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 24% of the 940 employees are represented by the United Steel Workers ("USW") and covered by a collective bargaining agreement that expires in January 2019. At December 31, 2017, 151 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. 177 employees were assigned to our marine storage segment at December 31, 2017, primarily in the Gulf and East Coast regions of the U.S. Approximately 16% of these employees are represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2020.

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10. 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 $8.9 million, $9.6 million and $9.9 million in 2015, 2016 and 2017, 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.

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, 2016 and 2017 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2016	2017	2016	2017
Change in benefit obligations:				
Benefit obligations at beginning of year	$209,591	$225,970	$11,314	$13,011
Service cost	18,179	20,497	235	243
Interest cost	7,950	9,865	489	475
Plan participants' contributions	—	—	217	280
Actuarial loss (gain)	1,050	59,686	1,481	(535)
Benefits paid	(10,053)	(11,484)	(725)	(714)
Settlement payments	(747)	(6,678)	—	—
Benefit obligations at end of year	225,970	297,856	13,011	12,760
Change in plan assets:				
Fair value of plan assets at beginning of year	142,742	166,906	—	—
Employer contributions	25,972	26,533	508	434
Plan participants' contributions	—	—	217	280
Actual return on plan assets	8,992	23,409	—	—
Benefits paid	(10,053)	(11,484)	(725)	(714)
Settlement payments	(747)	(6,678)	—	—
Fair value of plan assets at end of year	166,906	198,686	—	—

Funded status at end of year	$(59,064)	$(99,170)	$(13,011)	$(12,760)
Accumulated benefit obligations	$160,642	$206,480		

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The pension benefits in the previous table combine the Union plans with the Salaried plan. At December 31, 2016, the fair value of each of our plans' assets exceeded the accumulated benefit obligations of the related benefit plans. 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.

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.

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

	Pension Benefits		Other Postretirement Benefits	
	2016	2017	2016	2017
Amounts recognized in consolidated balance sheets:				
Current accrued benefit cost	$—	$—	$614	$625
Long-term pension and benefits	59,064	99,170	12,397	12,135
	59,064	99,170	13,011	12,760
Accumulated other comprehensive loss:				
Net actuarial loss	(62,013)	(100,474)	(7,881)	(6,597)
Prior service credit	3,429	3,248	—	—
	(58,584)	(97,226)	(7,881)	(6,597)
Net amount of liabilities and accumulated other comprehensive loss recognized in consolidated balance sheets	$480	$1,944	$5,130	$6,163

Net periodic benefit expense for the years ended December 31, 2015, 2016 and 2017 was as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2015	2016	2017	2015	2016	2017
Components of net periodic pension and postretirement benefit expense:						
Service cost	$18,890	$18,179	$20,497	$243	$235	$243
Interest cost[1]	7,754	7,950	9,865	438	489	475
Expected return on plan assets[1]	(8,037)	(8,913)	(10,266)	—	—	—
Amortization of prior service credit[1]	—	(181)	(181)	(3,713)	(3,335)	—
Amortization of actuarial loss[1]	6,306	4,645	5,622	885	880	749
Settlement cost[1]	—	202	2,460	—	—	—
Net periodic expense (credit)	$24,913	$21,882	$27,997	$(2,147)	$(1,731)	$1,467

[1] Upon adoption of ASU 2017-07 Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost on January 1, 2017, these components of net periodic benefit expense (credit) are reported on the consolidated statements of income as other (income) expense. See Note 2 – Summary of Significant Accounting Policies - New Accounting Pronouncements for further details about this

accounting change.

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Changes in plan assets and benefit obligations recognized in other comprehensive loss during 2015, 2016 and 2017 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2015	2016	2017	2015	2016	2017
Beginning balance	$(63,257)	$(62,279)	$(58,584)	$(1,696)	$(3,945)	$(7,881)
Net actuarial gain (loss)	(8,938)	(971)	(46,543)	579	(1,481)	535
Plan amendment	3,610	—	—	—	—	—
Amortization of prior service credit	—	(181)	(181)	(3,713)	(3,335)	—
Amortization of actuarial loss	6,306	4,645	5,622	885	880	749
Settlement cost	—	202	2,460	—	—	—
Amount recognized in other comprehensive loss	978	3,695	(38,642)	(2,249)	(3,936)	1,284
Ending balance	$(62,279)	$(58,584)	$(97,226)	$(3,945)	$(7,881)	$(6,597)

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 2018 are $7.0 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 2018 is $0.6 million.

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

	December 31,	
	2016	2017
Discount rate—Salaried plan	4.21%	3.70%
Discount rate—USW plan	4.08%	3.54%
Discount rate—IUOE plan	4.41%	3.79%
Discount rate—Other Postretirement Benefits	3.85%	3.43%
Rate of compensation increase—Salaried plan[1]	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 2016 and 2017 is calculated by 10-year age groupings beginning with ages 20-29 at 11% dropping to 4% by ages 70 and above.

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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,		
	2015	2016	2017
Discount rate—Salaried plan	3.91%	3.95%	4.21%
Discount rate—USW plan	3.56%	3.82%	4.04%
Discount rate—IUOE plan	3.93%	3.78%	4.41%
Discount rate—Other Postretirement Benefits	3.66%	4.00%	3.85%
Rate of compensation increase—Salaried plan[1]	5.50%	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 2018 is 5.4% decreasing systematically to 4.5% by 2083 for pre-65 year-old participants. As of December 31, 2017, a 1.0% change in assumed health care cost trend rates would have been immaterial to us.

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The fair values of the pension plan assets at December 31, 2016 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[a]:				
Small-cap fund	$3,465	$ 3,465	$ —	$ —
Mid-cap fund	3,472	3,472	—	—
Large-cap fund	26,323	26,323	—	—
International equity fund	16,797	16,797	—	—
Fixed Income Securities[a]:				
Short-term bond funds	4,414	4,414	—	—
Intermediate-term bond funds	23,629	23,629	—	—
Long-term investment grade bond funds	83,240	83,240	—	—
Other:				
Short-term investment funds	5,346	5,346	—	—
Group annuity contract	220	—	—	220
Fair value of plan assets	$166,906	$ 166,686	$ —	$ 220

(a) 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, 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[a]:				
Small-cap fund	$5,122	$ 5,122	$ —	$ —
Mid-cap fund	5,132	5,132	—	—
Large-cap funds	38,678	38,678	—	—
International equity fund	24,284	24,284	—	—
Fixed Income Securities[a]:				
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 fund	5,722	5,722	—	—

Group annuity contract	200	—	—	200
Fair value of plan assets	$198,686	$ 198,486	$ —	$ 200

(a) 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.

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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. Investments are made to match the durations of the short-term and intermediate-term pension liabilities. Additional investments are made to bring the overall investment allocation to 70% fixed income securities and 30% equity securities.

The target allocation and actual weighted-average asset allocation percentages at December 31, 2016 and 2017 were as follows:

	2016		2017	
	Actual	Target	Actual	Target
Equity securities	30%	30%	37%	30%
Fixed income securities	67%	67%	60%	67%
Other	3%	3%	3%	3%

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As of December 31, 2017, the benefit amounts expected to be paid from plan assets through December 31, 2027 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2018	$14,200	$ 625
2019	$13,854	$ 678
2020	$16,206	$ 715
2021	$16,556	$ 785
2022	$18,518	$ 844
2023 through 2027	$95,544	$ 4,021

Contributions estimated to be paid by us into the plans in 2018 are $28.1 million and $0.5 million for the pension and other postretirement benefit plans, respectively.

11. 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 $25.5 million and $4.7 million for the years ended December 31, 2015 and 2016, respectively.

Stacy P. Methvin was elected as an independent member of our general partner’s board of directors on April 23, 2015 and is also a director of one of our customers. Since April 23, 2015, we received tariff revenue of $9.3 million, $16.2 million and $16.6 million for the periods ending December 31, 2015, 2016 and 2017, respectively, from this customer. We recorded a receivable of $1.4 million and $1.6 million from this customer at December 31, 2016 and 2017, 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 4 – Investments in Non-Controlled Entities for a discussion of transactions with our joint venture affiliates.

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12. Debt

Long-term debt at December 31, 2016 and 2017 was as follows (in thousands):

	December 31,	
	2016	2017
Commercial paper	$50,000	$—
6.40% Notes due 2018	250,000	250,000
6.55% Notes due 2019	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
Face value of long-term debt	4,100,000	4,550,000
Unamortized debt issuance costs(1)	(26,948)	(29,472)
Net unamortized debt premium(1)	6,530	215
Net unamortized amount of gains from historical fair value hedges(1)	7,610	3,749
Long-term debt, net, including current portion	4,087,192	4,524,492
Less: current portion of long-term debt, net	—	250,974
Long-term debt, net	$4,087,192	$4,273,518

(1) 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, 2017, maturities of our debt were as follows: $250.0 million in July 2018; $550.0 million in 2019; $0 in 2020; $550.0 million in 2021; $0 in 2022; and approximately $3.2 billion thereafter.

2017 Debt Offering

On October 3, 2017, we issued $500.0 million of our 4.20% notes due 2047 in an underwritten public offering. The notes were issued at 99.341% of par. Net proceeds from this offering were approximately $491.6 million, after underwriting discounts and offering expenses of $5.1 million. The net proceeds from this offering were used to repay borrowings outstanding under our commercial paper program. The remaining proceeds were used for general partnership purposes, including capital expenditures.

Other Debt

Revolving Credit Facility. At December 31, 2017, 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

MAGELLAN MIDSTREAM PARTNERS, L.P.
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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, 2017. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2016 and 2017, respectively, there were no borrowings outstanding under this facility, with $6.3 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

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, 2017.

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 0.8% and 1.3%, respectively, for the year ended December 31, 2016 and 2017.

During the years ending December 31, 2015, 2016 and 2017, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $156.6 million, $181.7 million and $206.2 million, respectively.

13. 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.

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Our policies prohibit us from engaging in speculative trading activities.

Interest Rate Derivatives

We periodically enter into interest rate derivatives to hedge the fair value of debt or hedge against variability in interest rates. We record any ineffectiveness on interest rate derivatives designated as hedging instruments to interest expense and the change in fair value of interest rate derivatives that we do not designate as hedging instruments to other income or expense in our results of operations. For the effective portion of 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 the effective portion of 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 2016, we entered into $100.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2018. The fair values of these contracts at December 31, 2017 were recorded on our balance sheets as other current assets of $12.2 million, with the net offset recorded to other comprehensive income. We account for these agreements as cash flow hedges.

During 2015 and 2016, we entered into $250.0 million of forward-starting interest rate swap agreements to hedge 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 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 back-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 in the future currently in earnings as adjustments to product sales revenue, cost of product sales, or operating expenses, as applicable.

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Our open futures contracts at December 31, 2017 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
Futures - Economic Hedges	4.4 million barrels of refined products and crude oil	Between January 2018 and April 2019
Futures - Economic Hedges	1.5 million barrels of butane and natural gasoline	Between January 2018 and April 2019

Energy Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2016 and 2017, we had made margin deposits of $49.9 million and $36.7 million, respectively, 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, 2016 and 2017 (in thousands):

	Gross Amounts of Recognized Liabilities	Gross Amounts of Assets Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount[1]
Year Ended December 31, 2016	$ (36,798)	$ 6,060	$ (30,738)	$ 49,899	$ 19,161
Year Ended December 31, 2017	$ (38,936)	$ 12,851	$ (26,085)	$ 36,690	$ 10,605

(1) This represents the maximum amount of loss we would incur if our counterparties failed to perform on their derivative contracts.

(2) Net amount includes energy commodity derivative contracts classified as current liabilities of $25,694 and noncurrent liabilities of $391.

Impact of Derivatives on Our Financial Statements
Comprehensive Income
The changes in derivative activity included in AOCL for the years ended December 31, 2015, 2016 and 2017 were as follows (in thousands):

	Year Ended December 31,		
Derivative Gains (Losses) Included in AOCL	2015	2016	2017
Beginning balance	$(16,587)	$(30,126)	$(34,776)
Net loss on interest rate contract cash flow hedges	(14,904)	(6,699)	(1,937)

Reclassification of net loss (gain) on cash flow hedges to income	1,365	2,049	2,958
Ending balance	$(30,126)	$(34,776)	$(33,755)

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The following is a summary of the effect on our consolidated statements of income for the years ended December 31, 2015, 2016 and 2017 of derivatives that were designated as cash flow hedges (in thousands):

	Interest Rate Contracts			
	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Amount of Loss Reclassified from AOCL into Income Effective Portion	Ineffective Portion
Year Ended December 31, 2015	$(14,904)	Interest expense	$(1,365)	$ —
Year Ended December 31, 2016	$(6,699)	Interest expense	$(2,049)	$ —
Year Ended December 31, 2017	$(1,937)	Interest expense	$(2,958)	$ —

As of December 31, 2017, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $3.0 million. This amount relates to the amortization of losses on interest rate swap contracts over the life of the related debt instruments.

Until the third quarter of 2017, we had 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 remaining 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 tank bottoms. There was no ineffectiveness recognized on these hedges. 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 tank bottoms were as follows (in millions):

	Year Ended December 31,		
	2015	2016	2017
Gain (loss) recognized in other income/expense on derivative (futures contracts)	$15.6	$(9.0)	$4.8
Gain (loss) recognized in other income/expense on hedged item (tank bottoms)	$(15.6)	$9.0	$(4.8)

The differential between the current spot price and forward price was excluded from the assessment of hedge effectiveness for these fair value hedges. During 2015, 2016 and 2017, we recognized a gain of $1.0 million, $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.

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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, 2015, 2016 and 2017 of derivatives accounted for as economic hedges (in thousands):

		Amount of Gain (Loss) Recognized on Derivative Year Ended December 31,		
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	2015	2016	2017
Futures contracts	Product sales revenue	$68,426	$(38,584)	$(56,338)
Futures contracts	Cost of product sales	(8,997)	10,998	25,566
Futures contracts	Operating expenses	11,819	(5,000)	3,002
	Total	$71,248	$(32,586)	$(27,770)

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, 2016 and 2017 (in thousands):

	December 31, 2016			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ —	Energy commodity derivatives contracts, net	$ 3,079
Interest rate contracts	Other noncurrent assets	14,114	Other noncurrent liabilities	—
	Total	$ 14,114	Total	$ 3,079

	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	$ —	Energy commodity derivatives contracts, net	$ 173
Interest rate contracts	Other current assets	12,177	Other current liabilities	—
	Total	$ 12,177	Total	$ 173

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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, 2016 and 2017 (in thousands):

	December 31, 2016			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	$ 6,060	Energy commodity derivatives contracts, net	$ 33,719

	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

See Note 18 – Fair Value Disclosures for additional details regarding our derivative contracts.

14. 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 right-of-way contracts, several of which have cancellation penalties that include the requirement to remove our pipeline from the property for non-performance. 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 $25.7 million, $30.2 million and $34.8 million for the years ended December 31, 2015, 2016 and 2017, 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, 2017, were as follows (in millions):

2018	$34.5
2019	30.9
2020	27.5
2021	27.1
2022	26.5
Thereafter	116.0
Total	$262.5

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Lessor
We have entered into capacity leases and storage contracts with our customers with remaining terms from one to approximately 20 years that are accounted for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum payments receivable under these arrangements as of December 31, 2017, were as follows (in millions):

2018	$262.9
2019	246.6
2020	178.5
2021	119.6
2022	82.9
Thereafter	168.4
Total	$1,058.9

During 2017, we recognized contingent rental income from our condensate splitter in Corpus Christi, Texas in the amount of $24.9 million.

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, 2016 and 2017 was as follows (in millions):

	December 31, 2016	December 31, 2017
Total minimum lease payments receivable	$ 23.3	$ 19.2
Less: Unearned income	4.8	4.1
Recorded net investment in direct financing lease	$ 18.5	$ 15.1

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

	December 31, 2016	December 31, 2017
Other accounts receivable	$ 3.4	$ 1.1
Long-term receivables	15.1	14.0
Total	$ 18.5	$ 15.1

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

15.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

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limited partner units. The estimated units remaining available under the LTIP at December 31, 2017 totaled approximately 2.7 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"), which 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.

Non-deferred director awards are paid in units 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

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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 - 1/1/2017	313,696	$ 78.03	82,418	$ 75.36	396,114	$ 77.47
Units granted during 2017	189,544	$ 82.34	30,604	$ 79.10	220,148	$ 81.89
Units vested during 2017	(128,333)	$ 88.75	(50,099)	$ 82.46	(178,432)	$ 86.99
Units forfeited during 2017	(18,839)	$ 79.11	(1,819)	$ 77.05	(20,658)	$ 78.93
Non-vested units - 12/31/17	356,068	$ 76.40	61,104	$ 71.36	417,172	$ 75.66

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:					
2016 Awards	175,445	43,861	219,306	12/31/2018	$ 5.0
2017 Awards	180,623	—	180,623	12/31/2019	9.8
Time-Based Awards:					
2018 Vesting Date	31,174	—	31,174	12/31/2018	0.7
2019 Vesting Date	28,214	—	28,214	12/31/2019	1.6
2020 Vesting Date	1,716	—	1,716	12/31/2020	0.1
Total	417,172	43,861	461,033		$ 17.2

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

Weighted-Average Fair Value

The weighted-average fair value of awards granted during 2015, 2016 and 2017 was as follows:

	Performance-Based Awards		Time-Based Awards	
	Number of Unit Awards	Weighted-Average Fair Value	Number of Unit Awards	Weighted-Average Fair Value
Units granted during 2015	148,028	$ 88.78	26,421	$ 81.51
Units granted during 2016	193,344	$ 70.29	39,301	$ 64.76
Units granted during 2017	189,544	$ 82.34	30,604	$ 79.10

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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, 2017. 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)
12/31/2015	506,393	$27.7	$34.4
12/31/2016	361,711	$22.6	$27.4
12/31/2017	266,028	$19.9	$18.9

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 Taxes Paid (in millions)
January 2015	354,529	$17.8	$1.7	$19.5
February 2016	350,552	$14.4	$1.4	$15.8
January 2017	216,679	$13.9	$1.2	$15.1

Compensation Expense Summary

Equity-based incentive compensation expense for 2015, 2016 and 2017 was as follows (in thousands):

	Year Ended December 31,		
	2015	2016	2017
2013 awards	$10,658	$—	$—
2014 awards	7,471	7,928	28
2015 awards	4,917	4,874	6,645
2016 awards	—	4,304	6,125
2017 awards	—	—	5,025
Time-based awards	1,199	2,252	2,818
Total	$24,245	$19,358	$20,641

Allocation of LTIP
expense on our

consolidated statements of income:			
G&A expense	$23,937	$19,204	$20,463
Operating expense	308	154	178
Total	$24,245	$19,358	$20,641

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16. 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 and amortization expense and G&A expense that management does not consider when evaluating the core profitability of our separate operating segments.

	Year Ended December 31, 2015 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$974,505	$394,098	$176,143	$ —	$1,544,746
Product sales revenue	623,102	3,587	3,147	—	629,836
Affiliate management fee revenue	—	12,495	1,376	—	13,871
Total revenue	1,597,607	410,180	180,666	—	2,188,453
Operating expenses	376,279	89,001	62,221	(3,851)	523,650
Cost of product sales	442,621	3,278	1,374	—	447,273
(Earnings) losses of non-controlled entities	193	(63,918)	(2,758)	—	(66,483)
Operating margin	778,514	381,819	119,829	3,851	1,284,013
Depreciation and amortization expense	96,244	35,681	31,036	3,851	166,812
G&A expenses	93,567	35,721	20,660	—	149,948
Operating profit	$588,703	$310,417	$68,133	$ —	$967,253
Additions to long-lived assets	$310,907	$289,851	$70,290		$671,048
	As of December 31, 2015				
Segment assets	$2,991,322	$2,313,110	$677,914		$5,982,346
Corporate assets					59,221
Total assets					$6,041,567
Goodwill	$38,369	$12,082	$2,809		$53,260
Investments in non-controlled entities	$12,381	$739,470	$13,777		$765,628

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	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 and amortization 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

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	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 and amortization 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

17. 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 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.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $24.0 million and $19.3 million at December 31, 2016 and December 31, 2017, 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 $8.4 million, $5.9 million and $9.0 million for the years ended December 31, 2015, 2016 and 2017, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2016 were $4.1 million, of which $0.6 million and $3.5 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, 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. Amounts received from insurance carriers and other third parties related to environmental matters during 2015, 2016 and 2017 were $0.5 million, $0.9 million and $0.7 million, respectively.

Other

See Note 4 – Investments in Non-Controlled Entities for detail of our guarantee on behalf of Powder Springs.

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.

18. 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:

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

- 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 13 – 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 13 – 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.

- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2016 and 2017; 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, 2016 and 2017, based on the three levels established by ASC 820; Fair Value Measurements and Disclosures (in thousands):

			Fair Value Measurements as of December 31, 2016 using:		
Assets (Liabilities)	Carrying Amount	Fair Value	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	$(30,738)	$(30,738)	$(30,738)	$—	$ —
Interest rate contracts	$14,114	$14,114	$—	$14,114	$ —
Long-term receivables	$23,870	$23,870	$—	$—	$ 23,870
Debt	$(4,087,192)	$(4,262,321)	$—	$(4,262,321)	$ —

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

			Fair Value Measurements as of December 31, 2017 using:		
Assets (Liabilities)	Carrying Amount	Fair Value	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)	$ —

19.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.

The following table details the changes in the number of our limited partner units outstanding from January 1, 2015 through December 31, 2017:

Limited partner units outstanding on January 1, 2015	227,068,257
January 2015—Settlement of employee LTIP awards	354,529
During 2015—Other [(a)]	4,461
Limited partner units outstanding on December 31, 2015	227,427,247
February 2016—Settlement of employee LTIP awards	350,552
During 2016—Other [(a)]	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 [(a)]	23,961
Limited partner units outstanding on December 31, 2017	228,024,556

(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;

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

- 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.

Distributions

Distributions we paid during 2015, 2016 and 2017 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution
2/13/2015	$ 0.6950	$ 158,061
5/15/2015	0.7175	163,178
8/14/2015	0.7400	168,296
11/13/2015	0.7625	173,413
Total	$ 2.9150	$ 662,948
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

20. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2017.

Non-recognizable events

On January 31, 2018, we issued 170,604 limited partner units, of which 168,913 were issued to settle unit awards to certain employees that vested on December 31, 2017 and 1,691 were issued to settle the equity-based retainer paid to one independent director of our general partner.

On February 1, 2018, 294,054 unit awards were granted pursuant to our LTIP. These awards included both performance-based and time-based awards and have a 3-year vesting period that will end on December 31, 2020.

On February 14, 2018, we paid cash distributions of $0.92 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 6, 2018. The total distributions paid were $209.9 million.

Quarterly Financial Data

Summarized quarterly financial data is as follows (in thousands, except per unit amounts):

2016	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$519,816	$518,897	$551,782	$614,915
Total costs and expenses	$320,928	$307,742	$335,822	$382,825
Operating margin	$300,946	$304,350	$317,201	$339,599
Net income	$207,070	$187,859	$194,551	$213,291
Basic net income per limited partner unit	$0.91	$0.82	$0.85	$0.94
Diluted net income per limited partner unit	$0.91	$0.82	$0.85	$0.93
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

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-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner’s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner’s Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. There have been no changes in our internal control over financial reporting (as defined in Rule 13a - 15(f) of the Securities Exchange Act) during the quarter ending December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Our management, including our general partner’s Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that simple errors or mistakes can occur. Additionally, the individual acts of some persons, collusion by two or more people or management override can circumvent controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure and internal controls and make modifications as necessary; our intent in this regard is to maintain the disclosure and internal controls as systems change and conditions warrant.

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.

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)	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).
*(f)	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).
*(g)	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)	Second Supplemental Indenture dated as of July 14, 2008 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed July 14, 2008).
*(d)	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).
*(e)	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).
*(f)	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).

*(g)	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).
*(h)	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).
*(i)	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).
*(j)	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).
*(k)	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).
*(l)	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).
*(m)	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).

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 2018 Annual Incentive Program.
(c)	Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2018.
*(d)	Amended and Restated Director Deferred Compensation Plan effective January 28, 2014 (filed as Exhibit 10(d) to Form 10-K filed February 24, 2014).

Exhibit No.	Description
*(e)	$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).
*(f)	Executive Severance Pay Plan dated July 21, 2011 (filed as Exhibit 10.2 to Form 10-Q filed August 4, 2011).
(g)	Form of 2018 Performance Based Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
(h)	Form of 2018 Executive Retention Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
*(i)	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).
*(j)	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).
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
*(a)	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).
*(b)	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).
Exhibit 21	Subsidiaries of Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
(a)	Certification of Michael N. Mears, principal executive officer.
(b)	Certification of Aaron L. Milford, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
(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 16, 2018

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 16, 2018
/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 16, 2018
/s/ WALTER R. ARNHEIM Walter R. Arnheim	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018
/s/ ROBERT G. CROYLE Robert G. Croyle	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018
/s/ LORI A GOBILLOT Lori A Gobillot	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018
/s/ EDWARD J. GUAY Edward J. Guay	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018
/s/ STACY P. METHVIN Stacy P. Methvin	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018
/s/ JAMES R. MONTAGUE James R. Montague	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018
/s/ BARRY R. PEARL Barry R. Pearl	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2018