MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 19, 2016

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, 2015
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. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company.
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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, 2015 was $16,650,375,615.

As of February 18, 2016, there were 227,781,033 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 2016 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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FORM 10-K
PART I
Item 1. Business

(a) General Development of Business

We are a Delaware limited partnership formed in August 2000 and our 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 our general partner. Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries.
(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, 2015, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,500-mile refined products pipeline system with 52 terminals as well as 28 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,700 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 22 million barrels, of which 14 million are used for leased 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 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 increasingly 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 common carrier refined products pipeline system, independent terminals and our 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 9,500 miles from the Gulf Coast and covering a 15-state area across the central U.S. The system includes approximately 42 million barrels of aggregate usable storage capacity at 52 connected terminals. Our network of independent terminals includes 28 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,		
	2013	2014	2015
Percent of consolidated revenue	80%	77%	73%
Percent of consolidated operating margin	71%	68%	61%
Percent of consolidated total assets	59%	52%	50%

See Note 16—Segment Disclosures in the accompanying consolidated financial statements in Item 8 for additional financial information about our refined products segment.

Operations. Transportation, Terminalling and Ancillary Services. During 2015, 67% 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 32 of our pipeline system's 52 connected terminals. Revenue from terminalling and storage at the other 20 terminals on our refined products pipeline system is at privately negotiated rates.

In 2015, the products transported on our refined products pipeline system were comprised of 59% gasoline, 34% distillates and 7% aviation fuel and LPGs. The operating statistics below reflect our pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2013	2014	2015
Shipments (million barrels):			
Gasoline	239.7	256.1	268.1
Distillates	146.5	163.1	152.5
Aviation fuel	21.1	23.0	21.2
LPGs	7.8	9.9	9.7
Total shipments	415.1	452.1	451.5

Our refined products pipeline system generates additional revenue from leasing pipeline and storage tank capacity to shippers and from 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 a prescribed quantity of the products our shippers transport, which is commonly referred to as "tender deductions," on our pipelines 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 losses 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 losses 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.

Substantially all of the transportation and throughput services we provide are for third parties, and we do not take title to those products. We do take title to products related to our butane blending and fractionation activities on our refined products pipeline system. We also take title for our tender deductions on our refined products pipeline systems.

Commodity-Related Activities. Product sales revenue in our refined products segment primarily results from our butane blending and transmix fractionation activities, as well as from the sale of terminal product gains at our independent terminals. 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 either forward physical or New York Mercantile Exchange ("NYMEX") gasoline futures contracts at the time we purchase the related butane. These blending activities accounted for approximately 83% of the total product margin for the refined products segment during 2015. When the differential between the cost of butane and the price of gasoline is narrow, which generally occurs when crude oil prices are low, 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 its original components. 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 $163.6 million, $279.7 million and $180.5 million for the years ended December 31, 2013, 2014 and 2015, respectively. The amount of margin we earn from these activities fluctuates with changes in petroleum prices. Product margin is not a generally accepted accounting principle ("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

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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. We serve as construction manager and will serve as operator of the Powder Springs facility. This facility is expected to be operational in early 2017.

Markets and Competition. Shipments originate on our refined products pipeline system from direct connections to refineries, through interconnections with other interstate 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 48% 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 April 2015 projections provided by the Energy Information Administration, which represent the latest long-term outlook at this point, the demand for refined products in the primary market areas served by our pipeline system, known as 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 2015, approximately 72% of the products transported on our refined products pipeline system originated from 19 direct refinery connections and 28% 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 19 refineries:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
Black Elk Refining	Newcastle, WY
Calumet Specialty Products	Superior, WI
CHS	McPherson, KS
CVR Energy	Coffeyville, KS
CVR Energy	Wynnewood, OK
Flint Hills Resources	Rosemount, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
HollyFrontier	Cheyenne, WY
Marathon	Galveston Bay, TX
Marathon	Texas City, TX
Northern Tier	St. Paul, MN
Phillips 66	Ponca City, OK
Sinclair	Evansville, WY
Suncor Energy	Commerce City, CO
Valero	Ardmore, OK
Valero	Houston, TX
Valero	Texas City, TX
Western Refining	El Paso, TX

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	El Dorado, KS; Minneapolis, MN; Denver, CO	Various OK & KS refineries, Mandan, ND refinery, McKee, TX refinery
ONEOK Partners	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Phillips 66	Kansas City, KS; Denver, CO; Casper, WY	Borger, TX refinery, various Billings, MT area refineries
Shell	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries

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 more distant market. These agreements allow the two parties to reduce the volumes transported and 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 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 and integrated oil companies, wholesalers, retailers, traders, railroads, airlines and regional farm cooperatives. End markets for refined products deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots and military and commercial jet fuel users. 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 2015, approximately 42% of the shipments on our pipeline system were subject to these agreements. The average remaining life of these contracts was approximately four years as of December 31, 2015, with remaining terms of up to 13 years. While many of these 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, 2015, our refined products pipeline system had approximately 60 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies and farm cooperatives. Revenue attributable to these top 10 shippers for the year ended December 31, 2015 represented 46% of total revenue for our refined products segment and 54% 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 end of the contract period.

Our ammonia pipeline system ships product for three customers who own production facilities connected to our system. We have rolling three-year agreements 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.

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 is comprised of approximately 1,700 miles of crude oil pipelines with an aggregate storage capacity of approximately 22 million barrels of storage, of which 14 million are used for leased storage, including: (i) the Longhorn crude oil pipeline; (ii) our 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; (vi) the Gibson, Louisiana terminal; and (vii) the assets owned by our BridgeTex Pipeline Company, LLC ("BridgeTex"), Double Eagle Pipeline LLC (“Double Eagle”), Osage Pipe Line Company, LLC (“Osage”), Saddlehorn Pipeline Company, LLC ("Saddlehorn") and Seabrook Logistics, LLC ("Seabrook") joint ventures.

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

	Year Ended December 31,		
	2013	2014	2015
Percent of consolidated revenue	11%	15%	19%
Percent of consolidated operating margin	18%	23%	30%
Percent of consolidated total assets	26%	35%	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, which includes tender deductions, 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 throughput fees. We generally do not take title to the products we ship or store for our crude oil customers. We do own certain tank bottom assets at our crude oil terminal in Cushing, Oklahoma that are not sold in the normal course of business and are classified as long-term assets on our consolidated balance sheets. In addition, we are allowed under our tariffs to take 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. We take title to the petroleum products we obtain under our tender deductions on our crude oil pipeline systems.

The approximately 450-mile Longhorn crude oil pipeline has the capacity to transport up to 275,000 barrels of crude oil per day 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 that terminates in Texas City, Texas.

Our East Houston terminal includes approximately six million barrels of crude oil storage, with approximately three million barrels used for leased storage and three million barrels dedicated to the operation of the Longhorn and BridgeTex pipelines, which deliver crude oil to our East Houston terminal. (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. We are building additional storage at this location to facilitate movements on our pipeline systems or lease to customers.

Our Houston-area crude oil distribution system consists of more than 100 miles of pipeline segments that connect our East Houston terminal through several interchanges to various points, including multiple refineries throughout the Houston area and Texas City, Texas. In addition, it is directly connected to other third-party crude oil pipelines providing us access to crude oil from the Eagle Ford shale, the strategic crude oil hub in Cushing, Oklahoma and crude oil imports. In November 2014, we expanded our Houston-area crude oil distribution system by acquiring a 40-mile crude oil pipeline in the Houston Gulf Coast area.

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 that we can lease. 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, as well as short-haul pipeline connections with neighboring crude oil terminals.

We own approximately 400 miles of pipeline in Kansas and Oklahoma currently 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.

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Our Corpus Christi, Texas terminal includes approximately two million barrels of condensate storage, with a portion used for leased 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.

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 capable of transporting up to 300,000 barrels per day of Permian Basin crude oil from Colorado City, Texas to our East Houston terminal as well as operational crude oil storage at Colorado City of approximately one million barrels. The BridgeTex pipeline began operations in September 2014. We received construction fees and continue to receive operational management fees from 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 for capacity on our Houston area crude oil distribution system and 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 Energy Partners, L.P. ("Kinder"), that transports condensate from the Eagle Ford shale formation 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, Texas 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 Osage, which owns an approximately 135-mile pipeline that transports crude oil from Cushing to two refineries in Kansas. We receive a management fee for serving as the operator of Osage.

We own a 40% interest in Saddlehorn, a joint venture with an affiliate of Plains (40% interest) and an affiliate of Anadarko Petroleum Corporation ("Anadarko") (20% interest). Saddlehorn owns an undivided joint interest in an approximately 600-mile pipeline which will deliver various grades of crude oil from the DJ Basin, and potentially the broader Rocky Mountain production area, to Cushing, Oklahoma. Saddlehorn's undivided joint interest entitles it to a capacity of approximately 190,000 barrels per day. We serve as construction manager and will serve as operator of the Saddlehorn system once operations commence. The Saddlehorn pipeline is expected to begin operations in the third quarter of 2016.

We own a 50% interest in Seabrook, a joint venture with LBC Tank Terminals, LLC ("LBC"). Seabrook was formed in second quarter 2015 to construct, own and operate crude oil storage and pipeline infrastructure in the Houston Gulf Coast area. The assets to be constructed and owned by Seabrook include over 700,000 barrels of crude oil storage located adjacent to LBC's existing terminal in Seabrook, Texas and a pipeline that will connect Seabrook's storage facilities to an existing third-party pipeline that will transport crude oil to a Houston-area refinery. Subject to the receipt of permits and regulatory approvals, the new storage facility and pipeline infrastructure are expected to be operational in the first quarter of 2017.

Markets and Competition. Market conditions experienced by our crude oil pipelines vary significantly by location. Our 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. Permian Basin production may vary based on numerous factors including overall crude oil prices and changes in costs of production, while Gulf Coast refinery 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 refined products. Our 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. Indirectly, these pipelines also compete with other alternatives for delivering similar quality crude oil to the Gulf Coast, including pipelines from other producing basins such as the Eagle Ford shale or Gulf of Mexico, as well as waterborne imports. Competition is based primarily on tariff rates, proximity to both supply and demand centers, connectivity 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 system competes with other distribution facilities in the Houston area based primarily on tariff rates and connectivity.

Our crude oil storage facilities in Cushing serve customers who value Cushing's location as an interchange point for numerous interstate pipelines 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 shale formation for its supply and competes with other pipelines that are capable of transporting condensate from the Eagle Ford production area. Competition is based primarily on tariff rates, delivery mode and customer service. 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.

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 and destination. In addition, tariff rates can vary with the volume of spot barrel movements on our pipelines, which generally ship at higher rates than those charged to committed shippers. Based on generally accepted practices, we reserve 10% of the shipping capacity of our pipelines for spot shippers. Generally, we have secured long-term agreements 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 long-term take-or-pay customer agreements. For 2015, approximately 45% of the shipments on our wholly-owned crude oil pipelines were subject to long-term agreements. The average remaining life of these contracts was approximately three years as of December 31, 2015. As of December 31, 2015, 60% of our crude oil leased storage capacity was under contracts with terms in excess of one year, with an average remaining life of approximately two years. These contracts obligate the customer to pay for storage capacity reserved even if not used by the customer. Double Eagle and BridgeTex also have long-term contracts which support the capital investments in these pipeline systems.

MARINE STORAGE

We own and operate five marine storage terminals located along coastal waterways with approximately 25 million barrels of aggregate storage capacity and approximately one million additional barrels of storage jointly owned through our Texas Frontera, LLC joint venture ("Texas Frontera"). 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,		
	2013	2014	2015
Percent of consolidated revenue	9%	8%	8%
Percent of consolidated operating margin	11%	9%	9%
Percent of consolidated total assets	13%	12%	11%

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 large 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, 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 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 ship and barge and deliver products from this facility by 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 additional barrels of storage at our Galena Park terminal. This storage is leased under a long-term agreement with an affiliate of Texas Frontera. In addition to our portion of the net earnings of the joint venture, which we recognize as earnings of non-controlled entities, we receive a fee for operating the storage tanks of Texas Frontera, which we recognize as affiliate management fee revenue.

Markets and Competition. Our marine storage terminals compete with other independent terminals with respect to location, price, versatility and services provided. The competition primarily comes from integrated

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petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations. Similar to pipelines carrying petroleum products, the high capital costs deter competitors from building new storage facilities.

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, which provide us with a stable base of storage fee revenue. 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 2015, approximately 96% of our storage terminal capacity was utilized with the remaining 4% not utilized primarily due to tank integrity work throughout the year. As of December 31, 2015, approximately 80% 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 three years as of December 31, 2015. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

GENERAL BUSINESS INFORMATION

Major Customers

Major Customers. One customer accounted for 8%, 12% and 6% of our consolidated total revenue in 2013, 2014 and 2015, respectively. No other customer accounted for more than 10% of our consolidated revenues during these years. The majority of revenue from this customer resulted from sale of refined products that were generated in connection with our butane blending and fractionation activities, which are activities conducted by our refined products segment. We believe that other companies would purchase the petroleum products from us if this customer were unable or unwilling to do so.

Commodity Positions and Hedges

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 us carrying significant levels of petroleum product inventories. In addition, we hold positions related to our refined and crude pipeline systems' product gains and losses, crude tank bottoms and other crude inventories. We use derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale obligations. 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

Interstate Tariff Regulation. Our refined products pipeline system's interstate common carrier 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, including rates for all petroleum products, be filed with the FERC and posted publicly and that these rates be nondiscriminatory and “just and reasonable” when taking into account our cost of service. The rates of our interstate pipeline, which include 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 will be set at the annual change in the producer price index for finished goods ("PPI-FG") plus 1.23%. In general, we are permitted to adjust our rates to the ceiling established by the PPI-FG index plus 1.23%. 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. As an alternative to cost-of-service based rates, interstate pipeline companies may establish rates by obtaining authority to charge market-based rates in competitive markets or by agreement 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 deemed competitive by the FERC, in which case these rates can be adjusted at our discretion based on competitive factors.

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.

Intrastate Tariff Regulation. Some shipments on our refined products and ammonia pipeline systems, and substantially all shipments on our wholly-owned crude oil pipelines, move within a single state and thus are considered to be intrastate commerce. Our pipelines are subject to certain regulations with respect to such intrastate transportation by state regulatory authorities in the states of Colorado, Illinois, Iowa, Kansas, Minnesota, Nebraska, Oklahoma, Texas and Wyoming.

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 $1 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 $1 million or triple the monetary gain for violations of its anti-market manipulation regulations.

Should we violate these laws and regulations, we could be subject to material penalties, changes in the rates we can charge and liability to third parties.

Renewable Fuel Standard. We are an obligated party under the Environmental Protection Agency's ("EPA") Renewable Fuel Standard ("RFS") 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 2015 and expect to satisfy the requirements for 2016 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 annually unless adjusted by the EPA. The ability to incorporate increasing volumes of renewable fuel components into fuel products may be limited and could present challenges, which could increase our cost to comply with the RFS standards.

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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 costs 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 costs 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 and cash flow.

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $36.3 million and $31.4 million at December 31, 2014 and 2015, respectively. Environmental liabilities have been classified as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be substantially paid over the next 9 years.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $5.1 million and $2.6 million at December 31, 2014 and 2015, respectively.

Environmental Insurance Policies. We have insurance policies that provide coverage for environmental matters associated with liabilities arising from sudden and accidental releases of products applicable to all of our assets.

Hazardous Substances and Wastes. In most instances, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into water or soils, and include measures to control pollution of the environment. 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 are being or 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 or results of operation 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 Prevention of Significant Deterioration (“PSD”) pre-construction permits and Title V operating permits for GHG emissions, which does currently apply to our facilities. 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. We have adopted procedures for future required reporting.

While Congress has from time to time considered legislation to reduce emissions of greenhouse gases, the prospect for adoption of significant legislation at the federal level to reduce greenhouse gas emissions is perceived to be low at this time. Nevertheless, the current administration has announced it intends to adopt additional regulations to reduce emissions of greenhouse gases and to encourage greater use of low carbon technologies. Several states have implemented programs to reduce or monitor greenhouse gas emissions. 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 emissions of greenhouse gases could adversely affect demand for the oil that exploration and production operators produce, including our current or future customers, which could thereby reduce demand for our midstream services.

In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. To the extent the United States and other countries implement this agreement or impose other climate change regulations on the oil industry, it could have an adverse direct or indirect effect on our business.

The effect on our operations of legislative and regulatory efforts to regulate or restrict emissions of greenhouse gases in areas that we conduct business could adversely affect the 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.

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. HLPSA covers crude oil, refined products and anhydrous ammonia and requires any entity that owns or operates pipeline facilities to comply with such regulations, permit access to and copying of records and make certain reports and provide information as required by the Department of Transportation. Our assets are also subject to various federal security regulations, and we believe we are in substantial compliance with all applicable regulations.

The Department of Transportation requires operators of hazardous liquid interstate pipelines to develop and follow an integrity management program that provides for assessment of the integrity of all pipeline segments that could affect designated "high consequence areas," including high population areas, drinking water, commercially navigable waterways and ecologically sensitive resource areas. Segments of our pipeline systems have the potential to impact high consequence areas. 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 Department of Transportation through PHMSA.

Our marine terminals along coastal waterways are subject to U.S. Coast Guard regulations and comparable state statutes relating to the design, installation, testing, construction, 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 550 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 or 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. Legislation to reauthorize previous pipeline safety programs is being prepared and will likely include additional provisions designed to enhance pipeline safety. Compliance with such legislative and regulatory changes could have a material adverse effect on our results of operations.

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. 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 these 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 by us or our predecessor, 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, 2015, we had 1,640 employees, 903 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 25% of the 903 employees are represented by the United Steel Workers ("USW") and are covered by a collective bargaining agreement that expires January 31, 2019. At December 31, 2015, 98 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. The labor force of 170 employees assigned to our marine storage segment at December 31, 2015 was primarily located in the Gulf and East Coast regions of the U.S. Approximately 16% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires October 31, 2016.

(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 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 certain 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 and results of operations. However, these risks are not the only risks that we face. Our business could also be impacted by additional risks and uncertainties not currently known or that we currently deem 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 could 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 shifts and demand shifts between regions. If economic and market conditions remain uncertain or adverse conditions persist for an extended period, we could experience material impacts on our business, financial condition and 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 or decrease in the market prices of petroleum products, which may reduce supply or demand. Market prices for petroleum products are subject to wide fluctuations in response to changes in global and regional supply and demand over which we have no control. For example, legislation was passed in 2015 that removed the ban on crude oil exports from the U.S., which could impact the demand for our services in ways that we are unable to predict or control;

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

- 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; and
- an increase in the use of alternative fuel sources, such as ethanol, biodiesel, natural gas, fuel cells, solar, electric and battery-powered engines. Current laws require a significant increase in the quantity of ethanol and biodiesel used in transportation fuels between now and 2022. Increases in domestic natural gas production have resulted in lower U.S. natural gas prices, which in turn has led to the promotion by the natural gas industry and some politicians of natural gas as an alternative fuel. 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.

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. Since 2014, crude oil prices have fallen dramatically, as both domestic and international production increased while global economic conditions weakened, resulting in global crude supply that has significantly exceeded global crude demand. It is unclear when or if crude oil prices will return to levels seen in the period preceding the recent price collapse, and what impact the crude price environment will have on 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

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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 pipelines and terminals.

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. 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, testing, line repair, damage, reduced operating pressures or other causes could result in our being unable to deliver products to our customers from our terminals or receive products for storage or reduce shipments on our pipelines and 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. In addition, the profitability of the refineries that supply our facilities is subject to regional and sometimes 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 refined products or crude oil 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 lease renewals or renewals at substantially lower rates at our storage terminals or in leased storage along our pipelines could cause our leased storage revenue to decline, which could adversely impact our results of operations and the amount of cash we generate.

The revenue we earn from leased storage at our marine and crude oil terminals and along our pipeline system is provided for in contracts negotiated with our leased storage customers. Many of those contracts are for multi-year periods and require our customers to pay a fixed rate for storage capacity regardless of market conditions during the contract period. Changing market conditions, including changes in petroleum product supply or demand patterns, forward-price structure, financial market conditions, regulations, accounting rules or other factors could cause our customers to be unwilling to renew their leased storage contracts with us when those contracts terminate, or make them willing to renew only at lower rates or for shorter contract periods. Failure by our customers to renew their leased storage contracts on terms and at rates substantially similar to our existing contracts could result in lower utilization of our facilities and could cause our leased storage revenue to be more volatile. We have built a significant amount of new storage to meet market demand in recent years, as have several of our competitors. In addition, 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. Increased competition from other leased storage facilities could discourage our customers from renewing their contracts with us or cause them to renew their contracts with us at lower rates. We typically make capital investments in leased storage facilities only if we are able to secure contracts from our customers that support such investment; however, in some cases the initial term of those contracts is not sufficient to ensure that we fully earn the return we expect on those investments. If our customers do not renew such contracts or renew on less favorable terms, we could earn a return on those investments that is below our cost of capital, which could adversely affect our results of operations, financial position and cash flows.

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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. We compete with other transportation, storage and distribution alternatives on the basis of many factors, including but not limited to rates, service levels, 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, either of which 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 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 are also constructing a condensate splitter in Corpus Christi, 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, we could be forced to reduce the rates we charge for our services, the value of our assets could decrease and the returns on our investments in those markets could fail to meet our expectations.
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 lease storage capacity or be forced to reduce the rates we charge for leased storage capacity, 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 operation of our terminals. We also maintain product inventory related to these activities. Prices of petroleum products have historically experienced wide fluctuations. For example, petroleum product prices have decreased significantly since 2014. 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, exchange-traded futures contracts or over-the-counter transactions. These hedging arrangements may 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, exchange-traded futures contracts or over-the-counter transactions. To the extent these hedges do not qualify for hedge accounting treatment 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. To the extent these hedges are entered into on a public exchange, we may be required to post margin, which could result in material cash obligations. These contracts may be for the purchase or sale of product in markets or on 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 and 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 on the hedge contracts we have entered into 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. For the five-year period ending June 30, 2016, the indexing method provided for annual changes in rates by a percentage equal to the change in the PPI-FG plus 2.65%. Beginning July 1, 2016, the indexing method will provide 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 new FERC methodology. Further, in periods of general price deflation, the PPI-FG index could decrease, as it did in 2015, requiring us to reduce our index-based rates, even if the actual costs we incur to operate our assets increase. Changes in price levels that lead to decreases in our revenue or increases in the prices we pay to operate and maintain our assets could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Our business involves many hazards and operational risks, the occurrence of which could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

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. Our storage and pipeline facilities located near the

U.S. Gulf Coast, for example, have historically experienced damage and interruption of business due to hurricanes. 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.

Our assets may not be adequately insured or could have 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 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 those 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 most of the property on which our pipelines are constructed, and we rely on securing and retaining adequate rights-of-way and permits in order to operate our existing assets and complete growth projects.

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the relevant 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. Several rights-of-way for our pipelines and other real property assets are shared with other pipelines and 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 right-of-way grants. We are required to obtain 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. Similarly, we have obtained permits from railroad companies to cross over or under certain lands or rights-of-way, many of which are also revocable at the grantor's election. We are subject to potential increases in costs under our agreements with landowners, and if any of our rights-of-way or permits were revoked, our operations could be disrupted or we could be required to relocate our pipelines. Similarly, if we are unable to secure rights-of-way required for our growth projects, we could be forced to re-design or re-route those projects, which could result in substantial delays, reduced revenue or increased costs on those projects. Our ability to exercise the power of eminent domain varies by state and by circumstance, and the availability of the power and the compensation we must provide landowners in connection with any eminent domain action may be determined by a court. Failure to obtain required new rights-of-way or permits or retain rights-of-way and permits on existing terms could have a material adverse effect on our results of operations, financial position or cash flows, as well as 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 operate our assets and manage our businesses using a telecommunications network. A security breach of that network could result in improper operation of our assets, potentially including contamination or degradation of the products we transport, store or distribute, delays in the delivery or availability of our customers' product or releases of petroleum products for which we could be held liable. In addition, we rely on third-party systems, including for example the electric grid, 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 the operators of the third-party systems on which we depend may not have the resources or technical sophistication to anticipate or prevent every emerging type of cyber attack, and such an attack, or additional measures taken to prevent such an attack, could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

We also collect and store sensitive data on our networks, including our proprietary business information and information about our customers, suppliers and other counterparties, and personally identifiable information of our employees. The secure maintenance of this information is critical to our operations. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. We do not maintain specialized insurance for such attacks and any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information or regulatory penalties, could disrupt our operation, and could damage our reputation, any of which 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 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. 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. 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 that we believe complement our existing 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 will 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 could dilute our existing limited partner unitholders and 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, 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. 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. 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 $900 million 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 October 2016. We anticipate raising new capital to refinance 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, 2015, the face value of our outstanding fixed-rate debt was $3.2 billion. We had floating-rate borrowings of $280 million outstanding as of December 31, 2015 under our commercial paper program, 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, 2015, we were engaged in seven 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 could establish separate financing arrangements that could 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 upon 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 condensate splitter in Corpus Christi, Texas based on a commitment from a single customer, Trafigura, AG. In addition, we are participating in the Saddlehorn pipeline joint venture to transport crude oil from

Colorado to Cushing, Oklahoma, based primarily on the commitments of two shippers, affiliates of Noble Energy, Inc. and Anadarko. 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, our Saddlehorn pipeline project requires capital contributions from our joint venture co-owners, who are affiliates of Plains and Anadarko, as well as from a co-interest owner in certain assets with Saddlehorn, who is an affiliate of NGL Energy Partners, L.P. Nonperformance by these parties could result in increased costs or delays that could decrease our returns on this joint venture project.

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 and 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 and 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 or challenges by shippers of the rates we charge on our refined products and crude oil pipelines 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. 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 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 and make other concessions.

The FERC's ratemaking methodologies may limit our ability to set rates based on our true 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. In December 2015, the FERC established a price index level equal to the annual change in the PPI-FG expressed as a percentage plus 1.23% for the five-year period beginning July 1, 2016. When the PPI-FG falls, as it did in 2015, we will be required to reduce our rates that are subject to the FERC's price indexing methodology.

We establish market-based rates in approximately 60% of the markets for our refined products pipeline. The FERC allows us to establish rates based on conditions in individual markets without regard to the FERC's index level or our cost-of-service. If we were to lose our market-based rate authority, we would then be required to establish rates on some other basis, such as our cost-of-service.

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 and 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 or 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 and 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.

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 such 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

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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. 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. Legislation to reauthorize previous pipeline safety programs is being prepared and will likely include additional provisions designed to enhance pipeline safety. Compliance with such legislative and regulatory changes could 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 federal and state authorities and that could be subjected to increased regulatory costs, delays or liabilities. 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 Prevention of Significant Deterioration (“PSD”) pre-construction permits and Title V operating permits for GHG emissions, which does currently apply to our facilities. 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. We have adopted procedures for future required reporting.

Congress has from time to time considered legislation to reduce emissions of greenhouse gases. The current administration has announced it intends to adopt additional regulations to reduce emissions of greenhouse gases and to encourage greater use of low carbon technologies. Several states have implemented programs to reduce or monitor greenhouse gas emissions. 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 emissions of greenhouse gases could adversely affect demand for the oil that exploration and production operators produce, including our current or future customers, which could thereby reduce demand for our midstream services.

In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. To the extent the United States and other countries implement this agreement or impose other climate change regulations on the oil industry, it could have an adverse direct or indirect effect on our business.

The effect on our operations of legislative and regulatory efforts to regulate or restrict emissions of greenhouse gases in areas that we conduct business could adversely affect the 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 a 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 have the option to 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 business could be affected adversely by union disputes and strikes or work stoppages by our unionized employees.

As of December 31, 2015, approximately 15% of our workforce was covered by two collective bargaining agreements with different terms and dates of expirations. There can be no assurances that we will not 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.

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

At December 31, 2015, we had $4.8 billion of net property, plant and equipment, $0.8 billion of investments in non-controlled entities and $53.3 million of goodwill. U.S. GAAP requires us to periodically test long-lived assets, investments in non-controlled entities and goodwill for impairment. If we were to determine that any of our long-lived assets, investments in non-controlled entities or goodwill 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. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- We were conducting business in a state but had not complied with that particular state's partnership statute; or
- Your 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 would otherwise be held by state fiduciary duty 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. 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.

If you are not a citizenship eligible holder, your limited partner units 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

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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 currently a maximum of 35%, 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. 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.

The tax treatment of our structure 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. For example, from time to time the U.S. government considers substantive changes to the existing federal income tax laws that affect publicly traded partnerships. We are unable to predict whether any such changes or any other 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. Due to state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may 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.

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 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 recently 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.

The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit are counted only once. Our technical termination would not affect our classification as a partnership for federal income tax purposes, but could, among other things, result in the closing of our taxable year for all unitholders, which could result in our filing two tax returns for one fiscal year, and in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year results in more than 12 months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination.

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 24 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. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

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

Clean Water Act Information Requests and Claims. In July 2011, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release near Texas City, Texas in February 2011 (the "Texas Release"). In April 2012, we received a similar information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release near Nemaha, Nebraska in December 2011 (the "Nebraska Release"). In October 2015, we received a letter from the U.S. Department of Justice ("DOJ Letter") stating that the Clean Water Act claims arising out of the Texas Release, the Nebraska Release and a pipeline release near El Dorado, Kansas in May 2015, have all been referred to the U.S. Department of Justice for enforcement. The DOJ Letter proposed a settlement of Clean Water Act claims related to the three releases in the form of an enforceable commitment from us to take certain yet to be determined steps to prevent future releases and a civil penalty of $2.8 million. In response to the DOJ Letter, we will engage in discussions with the U.S. Department of Justice in an effort to settle the Clean Water Act claims on terms that are mutually agreeable. While the results cannot be predicted with certainty, we believe the ultimate resolution of these matters will not have a material impact on our results of operations, financial position or cash flows.
U.S. Oil Recovery, EPA ID No.: TXN000607093 Superfund Site. We have liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party ("PRP") under Section 107(a) of 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 $15,000 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 are in the process of voluntarily entering 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.

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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 15, 2016, we had 227,781,033 limited partner units outstanding that were owned by approximately 163,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $82.66 on December 31, 2014 and $67.92 on December 31, 2015. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2014 and 2015 were as follows:

	2014			2015		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$71.25	$60.23	$0.6125	$85.85	$72.90	$0.7175
2nd	$84.41	$69.56	$0.6400	$85.49	$73.36	$0.7400
3rd	$87.50	$77.14	$0.6675	$76.04	$55.05	$0.7625
4th	$90.08	$66.36	$0.6950	$70.26	$54.51	$0.7850

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

We must distribute all of our available cash, as defined in our partnership agreement, at the end of each quarter, less reserves established by our general partner's board of directors. We currently pay quarterly cash distributions of $0.785 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 50 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, 2010 and that all distributions or dividends were reinvested on a quarterly basis.

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
Magellan Midstream Partners, L.P.	$100	$128	$169	$257	$347	$296
Alerian MLP Index	$100	$114	$119	$152	$160	$108
S&P 500	$100	$102	$118	$157	$178	$181

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 and 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 and results of operations is included under Item 1A. Risk Factors of this report. Additionally, Note 2 – Summary of Significant Accounting Policies under Item 8. Financial Statements and Supplementary Data of this report provides 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 pay. 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 in the accompanying consolidated financial statements 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.

	Year Ended December 31,				
	2011	2012	2013	2014	2015
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenue[a]	$943,132	$1,016,166	$1,188,452	$1,459,267	$1,544,746
Product sales revenue	854,528	799,382	744,669	878,974	629,836
Affiliate management fee revenue	770	1,948	14,609	22,111	13,871
Total revenue	1,798,430	1,817,496	1,947,730	2,360,352	2,188,453
Operating expenses[a]	356,178	373,876	396,194	500,901	525,902
Cost of product sales	706,270	657,108	578,029	594,585	447,273
Earnings of non-controlled entities	(6,763)	(2,961)	(6,275)	(19,394)	(66,483)
Operating margin	742,745	789,473	979,782	1,284,260	1,281,761
Depreciation and amortization expense	121,179	128,012	142,230	161,741	166,812
G&A expense	98,669	109,403	132,496	148,288	151,329
Operating profit	522,897	552,058	705,056	974,231	963,620
Interest expense, net	107,465	113,766	118,206	121,519	143,177
Other expense (income)[b]	—	—	—	8,573	(1,015)
Income before provision for income taxes	415,432	438,292	586,850	844,139	821,458
Provision for income taxes	1,866	2,622	4,613	4,620	2,336
Net income	$413,566	$435,670	$582,237	$839,519	$819,122
Net income allocation:					
Limited partner interests	$413,629	$435,670	$582,237	$839,519	$819,122
Non-controlling owners' interest[c]	(63)	—	—	—	—
Net income	$413,566	$435,670	$582,237	$839,519	$819,122
Basic net income per limited partner unit	$1.83	$1.92	$2.57	$3.69	$3.60
Diluted net income per limited partner unit	$1.83	$1.92	$2.56	$3.69	$3.59
Balance Sheet Data:					
Working capital (deficit)[d]	$301,135	$307,658	$(241,543)	$(133,488)	$(374,218)
Total assets	$4,030,386	$4,404,987	$4,803,307	$5,501,409	$6,041,567
Long-term debt, net	$2,137,160	$2,378,328	$2,417,811	$2,967,019	$3,189,287
Owners' equity	$1,463,403	$1,515,702	$1,647,442	$1,868,233	$2,021,736
Cash Distribution Data:					
Cash distributions declared per unit[e]	$1.59	$1.88	$2.18	$2.62	$3.01
Cash distributions paid per unit[e]	$1.56	$1.78	$2.10	$2.51	$2.92

	Year Ended December 31,				
	2011	2012	2013	2014	2015
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	$574,030	$592,828	$693,985	$870,205	$777,021
Crude oil	74,225	91,367	176,420	295,830	381,365
Marine storage	91,571	102,323	106,198	114,712	119,524
Allocated partnership depreciation costs[f]	2,919	2,955	3,179	3,513	3,851
Operating margin	$742,745	$789,473	$979,782	$1,284,260	$1,281,761
Adjusted EBITDA and distributable cash flow:					
Net income	$413,566	$435,670	$582,237	$839,519	$819,122
Interest expense, net[g]	107,465	113,766	118,206	121,519	143,177
Depreciation and amortization[g]	121,179	128,012	142,230	161,741	166,812
Equity-based incentive compensation expense[h]	10,243	8,038	11,823	12,471	6,461
Loss on sale and retirement of assets	8,599	12,622	7,835	7,223	7,871
Commodity-related adjustments[i]	(22,370)	12,894	(339)	(56,288)	13,988
Other[j]	(2,504)	4,850	(409)	(8,724)	14,572
Adjusted EBITDA	636,178	715,852	861,583	1,077,461	1,172,003
Interest expense, net, excluding debt issuance cost amortization[g]	(105,634)	(111,679)	(115,782)	(119,186)	(140,464)
Maintenance capital	(70,002)	(64,396)	(76,081)	(77,806)	(88,685)
Distributable cash flow	$460,542	$539,777	$669,720	$880,469	$942,854
Operating Statistics:					
Refined products:					
Transportation revenue per barrel shipped	$1.175	$1.230	$1.313	$1.399	$1.439
Volume shipped (million barrels):					
Gasoline	208.9	223.7	239.7	256.1	268.1
Distillates	136.0	136.7	146.5	163.1	152.5
Aviation fuel	25.3	21.5	21.1	23.0	21.2
Liquefied petroleum gases	4.9	8.5	7.8	9.9	9.7
Total volume shipped	375.1	390.4	415.1	452.1	451.5
Crude oil:[k]					
Magellan 100%-owned assets:					
Transportation revenue per barrel shipped	$0.275	$0.305	$0.880	$1.192	$1.118
Volume shipped (million barrels)	43.2	72.0	113.2	185.5	209.9
Crude oil terminal average utilization (million barrels per month)	9.3	12.6	12.3	12.2	13.1
Select joint venture pipelines:					
BridgeTex - volume shipped (million barrels)[l]	—	—	—	18.3	75.2
Marine storage:					
Marine terminal average utilization (million barrels per month)	24.7	23.8	23.0	22.9	24.0

(a) Includes adjustment of tender deductions as discussed in Note 2 – Summary of Significant Accounting Policies and Note 16 Segment Disclosures of the consolidated financial statements included in Item 8 of this report.

(b) Other expense in 2014 and 2015 was a non-cash charge for the change in the differential between the current spot price and forward price on fair value hedges associated with our tank bottoms and linefill assets.

(c) Magellan Crude Oil, LLC ("MCO") was formed in 2010, and was partially owned by a private investment group. In February 2011, we acquired all of the non-controlling owners' interest in MCO. This amount reflects the private investment group's proportional share of the losses of MCO for the 2011 period.

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

(e) Cash distributions declared were determined based on the distributable cash flow 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.

(f) 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.

(g) In 2015, we adopted Accounting Standards Update ("ASU") No. 2015-03, Interest: Simplifying the Presentation of Debt Issuance Costs. Under this new accounting standard, we have reclassified debt issuance cost amortization expense as interest expense. We have added back the amount of these non-cash charges that were reclassified from depreciation and amortization expense to interest expense for purposes of calculating DCF. See Note 12 Debt of the consolidated financial statements included in Item 8 of this report.

(h) Excludes the tax withholdings on settlement of equity-based incentive awards, which were paid in cash.

(i) 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.

(j) Other primarily includes adjustments for earnings of and distributions received from non-controlled entities. In 2011, other included non-controlling owners' interests losses included in net income.

(k) Until the completion of our Longhorn crude oil pipeline reversal project in 2013, all of the volumes on our crude oil pipelines traveled short distances, and we charged a significantly lower tariff rate for such shipments than for the rest of our pipeline systems.

(l) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.

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 petroleum products. Our three operating segments including the assets of our joint ventures include:

- our refined products segment, comprised of our 9,500-mile refined products pipeline system with 52 terminals as well as 28 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,700 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 22 million barrels, of which 14 million are used for leased 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, 2015.

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

Overview

We are a key component of our nation’s energy infrastructure and provide essential transportation, distribution and storage services for our nation. Our pipeline systems are connected to nearly 50% of the refining capacity in the U.S. and can store more than 95 million barrels of petroleum products, such as gasoline, diesel fuel and crude oil. Our straight-forward business model is primarily focused on fee-based transportation and terminal activities.

Our assets continue to perform well with solid demand for our refined products and crude oil pipeline and terminal services. The low commodity prices in 2015 resulted in increased demand for gasoline, which was offset by lower diesel fuel demand in part due to reduced crude oil drilling activities in areas served by our assets. Overall, our total refined products throughput in 2015 was essentially the same as it was in 2014. Our marine terminals and long-haul crude oil pipelines are supported by take-or-pay contracts, which obligate customers to pay for reserved space even if not used by them. These attributes reinforce the stable, complementary nature of our business.

Growth Projects

We have initiated a number of large-scale growth projects over the past few years that have provided substantial growth for our company. We now benefit from a number of those recent investments, including the BridgeTex and Longhorn pipelines to deliver crude oil to the strategic Houston refining region. In 2015, we continued work on other significant projects that are expected to have a meaningful impact on our business going forward. Three major projects are expected to be operational by the end of 2016.

Our refined products business will benefit from the completion of the Little Rock pipeline in mid-2016. This project extends the reach of our existing pipeline system to the Little Rock, Arkansas market with the capacity to ship as much as 75,000 barrels per day of refined products from Mid-Continent and Gulf Coast refineries.

Our crude oil business will benefit from the completion of the Saddlehorn pipeline in the third quarter of 2016. This jointly-owned pipeline system will be capable of delivering up to 190,000 barrels per day of crude oil from the DJ Basin production region of Colorado to existing storage facilities in Cushing, Oklahoma, including storage owned by us. In addition, a 50,000 barrel per day condensate splitter and related storage and pipeline infrastructure at our Corpus Christi, Texas terminal is expected to be operational during the second half of the year.

We have additional projects underway due to continued customer demand for our services. Recently, we announced plans to connect our East Houston, Texas terminal to the Marketlink crude oil pipeline (TransCanada Corporation's Cushing, Oklahoma to Houston, Texas pipeline), the addition of jet fuel service capabilities for our Little Rock pipeline, and a new origin point on the BridgeTex pipeline in the Eaglebine crude oil production area that is supported by long-term committed volumes. While these projects are smaller in scale, we expect all to be attractive, low-risk opportunities to grow our business.

We also continue to evaluate well in excess of $500 million of other potential organic growth opportunities in all areas of our business. These include a healthy mix of opportunities for both refined products and crude oil. These opportunities include construction of incremental storage, new pipeline connections, expansion of our existing facilities, and continued development of our marine infrastructure capabilities in the Gulf Coast region.

We are also actively analyzing a variety of acquisition opportunities. We are careful in assessing acquisitions to ensure the assets are a good fit for our company. Maintaining our disciplined approach to growth through strategic acquisitions is something we believe our investors appreciate about us.

Advancing Our Marine Strategy

The recent elimination of crude oil export restrictions provides opportunities for additional energy infrastructure in our nation. In preparation for this industry change, we have been advancing our strategy to grow our marine capabilities along the Gulf Coast for both crude oil and refined products. During 2015, we announced our first step to execute this strategy with our new Seabrook Logistics joint venture to build 700,000 barrels of crude oil storage and related pipeline infrastructure with deepwater access in the Houston Gulf Coast area. We purchased 100 acres of ship channel property in Corpus Christi with a focus towards expanding our marine capabilities. This land effectively doubles the footprint of our existing Corpus Christi terminal and provides us space to construct up to four private deep-water ship docks and more than 5 million barrels of storage. We are also constructing an additional dock and expanding crude oil capabilities at our Galena Park, Texas marine terminal located on the Houston Ship Channel to meet growing industry demand for marine services. We continue to assess the need for additional storage at Galena Park as well and could build 1.6 million barrels at this location if supported by customer commitments.

Recent Developments

Cash Distribution. In January 2016, the board of directors of our general partner declared a quarterly cash distribution of $0.785 per unit for the period of October 1, 2015 through December 31, 2015. This quarterly cash distribution was paid on February 12, 2016 to unitholders of record on February 5, 2016. The total distribution paid on 227.8 million limited partner units outstanding was $178.8 million.

HoustonLink Pipeline Company, LLC ("HoustonLink"). HoustonLink was formed in first quarter 2016 to construct, own and operate a nine-mile crude oil pipeline connecting TransCanada Corporation's Marketlink crude oil pipeline to our East Houston terminal. We hold a 50% equity ownership interest in HoustonLink with TransCanada Corporation holding the other 50% equity ownership interest.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles (“GAAP”) measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation 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.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2015

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2014	2015	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:[(a)]				
Refined products	$946.6	$974.5	$27.9	3 %
Crude oil	341.9	394.1	52.2	15 %
Marine storage	170.7	176.1	5.4	3 %
Total transportation and terminals revenue	1,459.2	1,544.7	85.5	6 %
Affiliate management fee revenue	22.1	13.9	(8.2)	(37)%
Operating expenses:[(a)]				
Refined products	356.0	377.8	(21.8)	(6)%
Crude oil	83.2	89.5	(6.3)	(8)%
Marine storage	65.2	62.5	2.7	4 %
Intersegment eliminations	(3.5)	(3.9)	0.4	11 %
Total operating expenses	500.9	525.9	(25.0)	(5)%
Product margin:				
Product sales	879.0	629.8	(249.2)	(28)%
Cost of product sales	594.6	447.3	147.3	25 %
Product margin [(b)]	284.4	182.5	(101.9)	(36)%
Earnings of non-controlled entities	19.4	66.5	47.1	243 %
Operating margin	1,284.2	1,281.7	(2.5)	— %
Depreciation and amortization expense	161.7	166.8	(5.1)	(3)%
G&A expense	148.3	151.3	(3.0)	(2)%
Operating profit	974.2	963.6	(10.6)	(1)%
Interest expense (net of interest income and interest capitalized)	121.5	143.2	(21.7)	(18)%
Other expense (income)	8.6	(1.0)	9.6	112 %
Income before provision for income taxes	844.1	821.4	(22.7)	(3)%
Provision for income taxes	4.6	2.3	2.3	50 %
Net income	$839.5	$819.1	$(20.4)	(2)%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$1.399	$1.439		
Volume shipped (million barrels):				
Gasoline	256.1	268.1		
Distillates	163.1	152.5		
Aviation fuel	23.0	21.2		
Liquefied petroleum gases	9.9	9.7		
Total volume shipped	452.1	451.5		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$1.192	$1.118		
Volumes shipped (million barrels)	185.5	209.9		
Crude oil terminal average utilization (million barrels per month)	12.2	13.1		

Select joint venture pipelines:		
BridgeTex - volume shipped (million barrels)[c]	18.3	75.2
Marine storage:		
Marine terminal average utilization (million barrels per month)	22.9	24.0

(a) Includes adjustment of tender deductions as discussed in Note 2 – Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data. The amounts adjusted in 2014 for our refined products segment and crude oil segment are $24.8 million and $31.8 million, respectively.
(b) Product margin does not include depreciation or amortization expense.
(c) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.

Transportation and terminals revenue increased by $85.5 million, resulting from:

- an increase in refined products revenue of $27.9 million primarily attributable to higher transportation revenue and related ancillary revenue. Higher transportation revenue was favorably impacted by higher rates, which were favorably impacted by the mid-year 2014 and 2015 tariff rate increases of 3.9% and 4.6%, respectively. Volumes were essentially the same between periods as lower distillate shipments were offset by higher gasoline demand. Distillate shipments were 7% lower due to reduced demand from drilling activities and wet agricultural conditions in the areas served by our assets, whereas gasoline shipments increased 5% resulting from refinery turnarounds that increased demand on our system and lower gasoline prices that increased overall demand for gasoline. Additionally, revenue from our independent terminals increased primarily from two recent terminal acquisitions, revenue from leased storage along our pipeline system increased due to new customer contracts and our ammonia pipeline revenue increased due to higher rates and volumes, partially offset by lower tender deductions on our refined products pipeline;

- an increase in crude oil revenue of $52.2 million primarily due to revenue received in 2015 from BridgeTex to lease capacity on our Houston area crude oil distribution system and higher crude oil deliveries on our Longhorn pipeline, partially offset by lower tender deductions received from customers. Shipments on our Longhorn pipeline averaged approximately 260,000 barrels per day in 2015, an increase of approximately 30,000 barrels per day over 2014. Additionally, terminalling revenue was higher resulting from new leased storage contracts and from a customer buying out of its remaining storage agreement in 2015. Transportation revenue per barrel shipped was lower in the current period due to reduced average tariffs resulting from a lower volume of spot shipments on the Longhorn pipeline system, which ship at a higher rate, and more short-haul movements on our Houston-area crude oil distribution system in 2015; and

- an increase in marine storage revenue of $5.4 million primarily due to improved storage utilization from new contracts and less storage out of service for maintenance work and higher ancillary fees reflecting increased customer activities at our marine facilities. Higher average storage rates from contract renewals and escalations in the current year were offset by a one-time favorable contract adjustment in 2014.

Affiliate management fee revenue decreased $8.2 million due to lower construction management fees related to BridgeTex, as the pipeline became operational in late September 2014.

Operating expenses increased $25.0 million, resulting from:

- an increase in refined products expenses of $21.8 million primarily resulting from higher asset integrity spending and higher personnel costs, partially offset by more favorable product overages (which reduce operating expense) and lower power costs;

- an increase in crude oil expenses of $6.3 million primarily due to higher pipeline rental fees and costs associated with having more assets in crude oil service in 2015, such as higher personnel costs and property taxes, partially offset by more favorable product overages (which reduce operating expense); and

- a decrease in marine storage expenses of $2.7 million primarily attributable to lower asset integrity costs due to timing of project work and lower property taxes due to a favorable adjustment in the current year.

Product sales revenue resulted from our butane blending activities, transmix fractionation and product gains from our independent and marine terminals. We utilize New York Mercantile Exchange (“NYMEX”) contracts to hedge against changes in the price of petroleum products we expect to sell in the future, and we use butane futures agreements to hedge against changes in the price of butane we expect to purchase in future periods. 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 NYMEX contracts and butane futures agreements impacts our product margin. Product margin decreased $101.9 million primarily due to reduced gains on NYMEX contracts in the current year versus the prior year, partially offset by higher profits from our transmix fractionation activities

resulting from lower inventory costs and higher volumes and favorable lower-of-cost-or-market ("LCM") inventory adjustments (2014 included a $39.3 million LCM inventory adjustment to our fractionation and butane blending inventories due to the significant decline in commodity prices at the end of that year, compared to a $5.0 million LCM inventory adjustment in 2015). See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our NYMEX contracts.
Earnings of non-controlled entities increased $47.1 million primarily due to our share of earnings from BridgeTex, which began operations late in 2014.
Depreciation and amortization expense increased $5.1 million in 2015 primarily due to expansion capital projects placed into service and a $1.8 million asset impairment charge recognized in 2015, partially offset by the $9.4 million acceleration of depreciation for pipeline, terminal and related assets during 2014 that we later sold.

G&A expense increased $3.0 million between periods primarily due to higher personnel costs resulting from an increase in employee headcount and higher pension and benefit costs, partially offset by lower costs associated with deferred board of director compensation and equity-based compensation resulting from a decrease in the price of our limited partner units in 2015.
Interest expense, net of interest income and interest capitalized, increased $21.7 million in 2015 primarily due to higher debt outstanding in 2015 compared to 2014 and lower capitalized interest since we are no longer capitalizing interest expense related to BridgeTex, which began operations in late September 2014. Our average outstanding debt increased from $2.9 billion in 2014 to $3.3 billion in 2015 primarily due to borrowings for expansion capital expenditures, including $500.0 million of senior notes issued in March 2015. Our weighted-average interest rate decreased from 4.9% at December 31, 2014 to 4.7% at December 31, 2015 due to the impact of our commercial paper borrowings and March 2015 debt issuances, which are both at lower weighted-average rates than the debt we retired in mid-2014.
Other expense (income) included $9.6 million of favorable non-cash adjustments for the change in the differential between the current spot price and forward price on fair value hedges associated with our crude oil tank bottoms and linefill assets.
Provision for income taxes was $2.3 million favorable due to a reduction in the franchise tax rate for the state of Texas in 2015.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2014

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2013	2014	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:[a]				
Refined products	$826.2	$946.6	$120.4	15%
Crude oil	203.4	341.9	138.5	68%
Marine storage	158.8	170.7	11.9	7%
Total transportation and terminals revenue	1,188.4	1,459.2	270.8	23%
Affiliate management fee revenue	14.6	22.1	7.5	51%
Operating expenses:[a]				
Refined products	295.8	356.0	(60.2)	(20)%
Crude oil	44.1	83.2	(39.1)	(89)%
Marine storage	59.4	65.2	(5.8)	(10)%
Intersegment eliminations	(3.1)	(3.5)	0.4	13%
Total operating expenses	396.2	500.9	(104.7)	(26)%
Product margin:				
Product sales	744.7	879.0	134.3	18%
Cost of product sales	578.0	594.6	(16.6)	(3)%
Product margin [b]	166.7	284.4	117.7	71%
Earnings of non-controlled entities	6.3	19.4	13.1	208%
Operating margin	979.8	1,284.2	304.4	31%
Depreciation and amortization expense	142.2	161.7	(19.5)	(14)%
G&A expense	132.6	148.3	(15.7)	(12)%
Operating profit	705.0	974.2	269.2	38%
Interest expense (net of interest income and interest capitalized)	118.2	121.5	(3.3)	(3)%
Other expense	—	8.6	(8.6)	n/a
Income before provision for income taxes	586.8	844.1	257.3	44%
Provision for income taxes	4.6	4.6	—	—%
Net income	$582.2	$839.5	$257.3	44%
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$1.313	$1.399		
Volume shipped (million barrels):				
Gasoline	239.7	256.1		
Distillates	146.5	163.1		
Aviation fuel	21.1	23.0		
Liquefied petroleum gases	7.8	9.9		
Total volume shipped	415.1	452.1		
Crude oil:				
Magellan 100%-owned assets:				
Transportation revenue per barrel shipped	$0.880	$1.192		
Volumes shipped (million barrels)	113.2	185.5		
Crude oil terminal average utilization (million barrels per month)	12.3	12.2		

Select joint venture pipelines:		
BridgeTex - volume shipped (million barrels)[c]	—	18.3
Marine storage:		
Marine terminal average utilization (million barrels per month)	23.0	22.9

(a) Includes adjustment of tender deductions as discussed in Note 2 – Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data. The amounts adjusted for our refined products segment are $25.1 million and $24.8 million for 2013 and 2014, respectively. The amounts adjusted for our crude oil segment are $25.0 million and $31.8 million for 2013 and 2014, respectively.

(b) Product margin does not include depreciation or amortization expense.

(c) These volumes reflect the total shipments for the BridgeTex pipeline, which is owned 50% by us.

Transportation and terminals revenue increased by $270.8 million, resulting from:

- an increase in refined products revenue of $120.4 million. Excluding the pipeline systems we acquired in the second half of 2013, refined products revenue increased approximately $92.0 million primarily due to a 4% increase in transportation volumes, higher average rates and higher ancillary revenues associated with increased activity. Shipments were higher primarily due to increased demand for distillates and gasoline in the markets we serve. The average rate per barrel in 2014 was impacted by the mid-year 2013 and 2014 tariff rate increases of 4.6% and 3.9%, respectively, and more long-haul shipments at higher rates;

- an increase in crude oil revenue of $138.5 million primarily due to crude oil deliveries from our Longhorn pipeline, which represented approximately 90% of the increase. Our Longhorn pipeline averaged approximately 125,000 barrels per day during 2013 after its mid-April start date, while deliveries averaged approximately 230,000 barrels per day during 2014; and

- an increase in marine storage revenue of $11.9 million primarily due to higher storage rates from contract renewals and annual escalations, a one-time adjustment associated with one of our storage contracts (which increased 2014 revenues) and the one-time benefit from a customer buying out of its remaining storage contract in 2014.

Affiliate management fee revenue increased $7.5 million, primarily resulting from an increase in management fees received from BridgeTex to reimburse us for our costs of providing construction services to BridgeTex during 2014.

Operating expenses increased $104.7 million, resulting from:

- an increase in refined products expenses of $60.2 million. Excluding the pipeline systems we acquired in the second half of 2013, refined products expenses increased approximately $39.0 million primarily due to additional costs in 2014 for property taxes, personnel, pipeline rental primarily related to a pipeline segment we began leasing in 2014, asset integrity and power costs, less favorable product overages (which reduce operating expenses), as well as a favorable adjustment in 2013 of an accrual for potential air emission fees at our East Houston facility;

- an increase in crude oil expenses of $39.1 million primarily due to higher shipments on our Longhorn pipeline in 2014, including higher power expenses and pipeline rental fees, as well as higher personnel costs, asset integrity expense and property taxes as a result of having more assets in crude oil service; and

- an increase in marine storage expenses of $5.8 million primarily due to a favorable adjustment in 2013 of an accrual for potential air emission fees at our Galena Park facility, partially offset by lower losses on asset retirements in the current year.

Product margin increased $117.7 million primarily due to gains on NYMEX contracts in 2014 versus losses in 2013, and higher profits from our butane blending activities resulting from higher volumes sold and lower butane costs, partially offset by a $39.3 million LCM inventory adjustment to our fractionation and butane blending inventories in 2014 due to the significant decline in commodity prices at the end of that year.
Earnings of non-controlled entities increased $13.1 million primarily due to contributions from BridgeTex, which began operations late in 2014.
Depreciation and amortization expense increased $19.5 million in 2014 primarily due to expansion capital projects placed into service and acquisitions. Additionally, based on an impairment analysis we performed, we accelerated the depreciation of a certain terminal and related assets for the year ended December 31, 2014 by $9.4 million.

G&A expense increased $15.7 million between periods primarily due to higher personnel costs resulting from an increase in employee headcount, higher pension and benefit costs and higher equity-based compensation costs primarily due to a higher price for our limited partner units.
Interest expense, net of interest income and interest capitalized, increased $3.3 million in 2014. Our average outstanding debt increased from $2.5 billion in 2013 to $2.9 billion in 2014 primarily due to borrowings for expansion capital expenditures, including $300.0 million of senior notes issued in October 2013 and $250.0 million of senior notes issued in March 2014. Our weighted-average interest rate decreased from 5.2% at December 31, 2013 to 4.9% at December 31, 2014.
Other expense for 2014 includes an $8.6 million non-cash charge for the change in the differential between the spot price and forward price on fair value hedges associated with our crude oil tank bottoms and linefill assets.

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, 2013, 2014 and 2015 to net income, which is the nearest comparable GAAP financial measure, is as follows (in millions):

	Year Ended December 31,		
	2013	2014	2015
Net income	$582.2	$839.5	$819.1
Interest expense, net[1]	118.2	121.5	143.2
Depreciation and amortization[1]	142.3	161.8	166.8
Equity-based incentive compensation expense[2]	11.8	12.5	6.5
Loss on sale and retirement of assets	7.8	7.2	7.9
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with future product transactions[3]	8.1	(87.5)	(47.8)
Derivative (losses) gains recognized in previous periods associated with product sales completed in the period[4]	(6.4)	(8.1)	96.1
Lower-of-cost-or-market inventory adjustments[5]	(2.0)	39.3	(34.3)
Total commodity-related adjustments	(0.3)	(56.3)	14.0
Earnings of non-controlled entities, net of distributions received	(0.4)	(8.7)	14.5
Adjusted EBITDA	861.6	1,077.5	1,172.0
Interest expense, net, excluding debt issuance cost amortization[1]	(115.8)	(119.2)	(140.5)
Maintenance capital[6]	(76.1)	(77.8)	(88.7)
DCF	$669.7	$880.5	$942.8

(1) In 2015, we adopted ASU No. 2015-03, Interest: Simplifying the Presentation of Debt Issuance Costs. Under this new accounting standard, we have reclassified debt issuance cost amortization expense as interest expense. We have added back debt issuance cost amortization expense included in interest expense for purposes of calculating DCF as follows: For the twelve months ended December 31, 2013, 2014 and 2015, $2.4 million, $2.3 million and $2.7 million, respectively.

(2) Because we intend to satisfy vesting of unit awards under our equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for DCF purposes. Total equity-based incentive compensation expense for the years ended December 31, 2013, 2014 and 2015 was $24.1 million, $27.3 million and $24.3 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2013, 2014 and 2015 of $12.3 million, $14.8 million and $17.8 million, respectively, for equity-based incentive compensation units that vested at the previous year end, which reduce DCF.

(3) 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 and linefill assets 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.

(4) When we physically sell products that we have economically hedged (but were not designated as hedges for accounting purposes), we include in our DCF calculations the full amount of the gain or loss realized on the economic hedges in the period that the underlying product sales occur.

(5) We add the amount of LCM adjustments on inventory and firm purchase commitments we recognize in each applicable period to determine DCF as these are non-cash charges against income. In subsequent periods when we physically sell or purchase the related products, we deduct the LCM adjustments previously recognized to determine DCF.

(6) 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.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Operating Activities. Net cash provided by operating activities was $773.1 million, $1,107.3 million and $1,069.7 million for the years ended December 31, 2013, 2014 and 2015, respectively. The $37.6 million decrease from 2014 to 2015 was due to lower net income related to activities previously described and changes in our working capital, partially offset by adjustments to non-cash items. The $334.2 million increase from 2013 to 2014 was due to higher net income related to activities previously described, changes in our working capital and adjustments to non-cash items.

Investing Activities. Net cash used by investing activities for the years ended December 31, 2013, 2014 and 2015 was $882.0 million, $830.0 million and $810.8 million, respectively. During 2015, we spent $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, which we account for as investments in non-controlled entities. During 2014, we spent $366.4 million for capital expenditures, which included $77.8 million for maintenance capital and $288.6 million for expansion capital. Also during 2014, we contributed capital of $408.0 million in conjunction with our joint venture capital projects (primarily BridgeTex) and we acquired from a subsidiary of Oxy its ownership interest in a 40-mile crude oil pipeline in the Houston Gulf Coast area for $75.0 million. During 2013, we spent $383.8 million for capital expenditures, which included $76.1 million for maintenance capital and $307.7 million for expansion capital. Our expansion capital spending during 2013 was primarily for the Longhorn pipeline reversal project. Also during 2013, we contributed capital of $250.5 million in conjunction with our joint venture capital projects, acquired approximately 800 miles of refined petroleum products pipelines for $192.0 million and spent $22.5 million on an asset acquisition.

Financing Activities. Net cash used by financing activities for the years ended December 31, 2013, 2014 and 2015 was $194.1 million, $285.5 million and $247.3 million, respectively. 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 award grants were settled by issuing 354,529 limited partner units and distributing those units to the long-term incentive plan ("LTIP") participants, resulting in payments of associated tax withholdings of $17.8 million. During 2014, we paid cash distributions of $568.8 million to our unitholders. Additionally, we received net proceeds of $257.7 million from borrowings under long-term notes and $296.9 million from borrowings under our commercial paper program, which were used in part to repay our $250.0 million of 6.45% notes due June 1, 2014, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital. Also, in 2014, the cumulative amounts of the 2011 equity-based incentive compensation award grants were settled by issuing 387,216 limited partner units and distributing those units to the LTIP participants, resulting in payments of associated tax withholdings of $14.8 million. During 2013, we paid cash distributions of $475.5 million to our unitholders. Additionally, we received net proceeds of $298.7 million from borrowings under long-term notes, which were used to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital and acquisitions. Also, in 2013, the cumulative amounts of the 2010 equity-based

incentive compensation award grants were settled by issuing 476,682 limited partner units and distributing those units to the LTIP participants, resulting in payments of associated tax withholdings of $12.3 million.
The quarterly distribution amount related to fourth quarter 2015 earnings was $0.785 per unit, which was paid in February 2016. If we are able to meet management's targeted distribution growth of 10% during 2016 and the number of outstanding limited partner units remains at 227.8 million, total cash distributions of approximately $754.0 million will be paid to our unitholders related to 2016 earnings. Management believes we will have sufficient distributable cash flow to fund these distributions.

Capital Requirements

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

- 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; and

- 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.

During 2015, we spent $534.6 million for organic growth capital and contributed $152.5 million to our joint venture capital projects primarily related to our investment in Saddlehorn. Additionally, we spent $54.7 million to acquire an independent refined products terminal in Atlanta, Georgia. Based on the progress of expansion projects already underway, we expect to spend approximately $800.0 million for expansion capital during 2016, with an additional $100.0 million thereafter to complete our current projects. See Growth Projects above for additional information.

During 2015, our maintenance capital spending was $88.7 million. For 2016, we expect to spend approximately $90.0 million on maintenance capital.

Liquidity

Cash generated from operations is our primary 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 of the consolidated financial statements included in Item 8 of this report for detail of our borrowings and debt outstanding at December 31, 2014 and 2015). 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, 2015 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$3,430.0	$250.0	$250.0	$830.0	$2,100.0
Interest obligations(1)	2,096.1	162.9	296.1	212.0	1,425.1
Operating lease obligations	177.9	26.5	49.2	21.1	81.1
Pension and postretirement medical obligations(2)	78.2	23.5	45.3	1.5	7.9
Purchase commitments:					
Product purchase commitments(3)	79.8	72.9	6.9	—	—
Utility purchase commitments	11.9	7.4	3.5	0.8	0.2
Derivative instruments(4)	—	—	—	—	—
Equity-based incentive awards(5)	48.3	27.7	20.6	—	—
Capital project purchase obligations	151.6	151.0	0.6	—	—
Maintenance obligations	71.6	71.5	0.1	—	—
Other	11.0	7.0	4.0	—	—
Total	$6,156.4	$800.4	$676.3	$1,065.4	$3,614.3

(1) At December 31, 2015, we had no borrowings outstanding under our revolving credit facility. For purposes of this table, we have reflected no assumed borrowings under our revolving credit facility for any periods presented. We assumed that the amounts outstanding under our commercial paper program at December 31, 2015 would be repaid in October 2020, the maturity date of our revolving credit facility, which supports our commercial paper program. Further, we have included interest obligations based on the stated amounts of our fixed-rate obligations. For our variable-rate debt, we calculated interest obligations assuming the weighted-average interest rate of our variable-rate debt at December 31, 2015 on amounts outstanding through the assumed repayment date.

(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 as of December 31, 2015. Also, we have excluded certain product purchase agreements for which there is no specified or minimum quantity.

(4) As of December 31, 2015, we had entered into commodity-related derivative contracts representing 5.2 million barrels of petroleum products that we expect to sell in the future and 0.9 million barrels of butane we expect to purchase in the future. At December 31, 2015, we had recorded a net asset of $42.7 million and received margin deposits of $24.3 million. We have excluded from this table the future net cash outflows, if any, under these derivative agreements and the amounts of future margin deposit requirements because those amounts are uncertain.

(5) Represents the grant date fair value of unit awards accounted for as equity plus the December 31, 2015 re-measured grant date fair value of unit awards accounted for as liabilities. The total equity-based incentive awards liability is determined by multiplying the grant date per unit fair value by the number of unit awards granted, multiplied by the percentage of the requisite service period completed, multiplied by the estimated payout percentage of the unit awards at December 31, 2015. Settlements of these unit awards will differ from these reported amounts primarily due to differences between actual and current estimates of payout percentages and forfeitures, changes in our unit price between December 31, 2015 and the vesting dates of the unit awards 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

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 NYMEX 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 NYMEX contracts to hedge against changes in the price of refined products and crude oil that we expect to sell in future periods. We use and account for those NYMEX contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use NYMEX contracts to economically hedge against changes in the price of butane we expect to purchase in the future as part of our butane blending activities. As of and for the year ended December 31, 2015, a summary of our NYMEX hedging activities is as follows:

Derivative Contracts Designated as Hedges

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude oil tank bottoms and linefill. These contracts, which we are accounting for as fair value hedges, mature between January 2016 and November 2017. Through December 31, 2015, the cumulative amount of gains from these agreements was $27.9 million. The cumulative gains from these fair value hedges were recorded as adjustments to the asset being hedged, and there has been no ineffectiveness recognized for these hedges. We exclude the differential between the current spot price and forward price from our assessment of hedge effectiveness for these fair value hedges. The net change in the amounts excluded from our assessment of hedge effectiveness during 2015 was a gain of $1.0 million, which we recognized as other income on our consolidated statements of income.

Derivative Contracts Not Designated as Hedges – Open

- NYMEX contracts covering 3.4 million barrels of refined products and crude oil related to our butane blending, fractionation and certain crude oil inventory. These contracts mature between January and December 2016 and are being accounted for as economic hedges. Through December 31, 2015, the cumulative amount of net unrealized gains associated with these agreements was $41.3 million. We recorded these gains as an adjustment to product sales revenue, all of which was recognized in 2015.

- NYMEX contracts covering 1.1 million barrels of refined products and crude oil related to inventory we carry that resulted from pipeline product overages. These contracts, which mature between January and April 2016, are being accounted for as economic hedges. Through December 31, 2015, the cumulative amount of net unrealized gains associated with these agreements was $3.1 million. We recorded these gains as an adjustment to operating expense, all of which was recognized in 2015.

- NYMEX contracts covering 0.9 million barrels of butane purchases that mature between January and December 2016, which are being accounted for as economic hedges. Through December 31, 2015, the cumulative amount of net unrealized losses associated with these agreements was $5.2 million. We recorded these losses as an adjustment to cost of product sales, all of which was recognized in 2015.

Derivative Contracts Not Designated as Hedges – Settled

- We settled NYMEX contracts covering 10.3 million barrels of refined products related to economic hedges of products from our butane blending and fractionation activities that we sold during 2015. We recognized a gain of $27.1 million in 2015 related to these contracts, which we recorded as an adjustment to product sales revenue.

- We settled NYMEX contracts covering 6.3 million barrels of refined products and crude oil related to economic hedges of product inventories from product overages on our pipeline systems that we sold during

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2015. We recognized a gain of $8.7 million in 2015 on the settlement of these contracts, which we recorded as an adjustment to operating expense.

- We settled NYMEX contracts covering 1.2 million barrels related to economic hedges of butane purchases we made during 2015 associated with our butane blending activities. We recognized a loss of $3.8 million in 2015 on the settlement of these contracts, which we recorded as an adjustment to cost of product sales.

Impact of Commodity Derivatives on Results of Operations

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

	Year Ended December 31, 2013			
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
NYMEX gains (losses) recognized on settled contracts during the period	$0.6	$2.3	$(3.6)	$(0.7)
NYMEX losses from cash flow hedges that were reclassified from accumulated other comprehensive loss during the period	(4.4)	—	—	(4.4)
NYMEX gains (losses) recorded on open contracts during the period	(6.8)	0.4	(0.2)	(6.6)
Net impact of NYMEX contracts	$(10.6)	$2.7	$(3.8)	$(11.7)

	Year Ended December 31, 2014				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Expense	Net Impact on Results of Operations
NYMEX gains (losses) recognized on settled contracts during the period	$61.5	$(6.5)	$9.6	$—	$64.6
NYMEX gains (losses) recorded on open contracts during the period	83.8	(10.6)	8.2	(8.6)	72.8
Net impact of NYMEX contracts	$145.3	$(17.1)	$17.8	$(8.6)	$137.4

	Year Ended December 31, 2015				
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	Net Impact on Results of Operations
NYMEX gains (losses) recognized on settled contracts during the period	$27.1	$(3.8)	$8.7	$—	$32.0
NYMEX gains (losses) recorded on open contracts during the period	41.3	(5.2)	3.1	1.0	40.2
Net impact of NYMEX contracts	$68.4	$(9.0)	$11.8	$1.0	$72.2

Pipeline Tariff Increase. The FERC regulates the rates charged on interstate common carrier pipeline operations primarily through an indexing methodology, which establishes the maximum amount by which tariffs can be adjusted each year. Approximately 40% of our refined products tariffs are subject to this indexing methodology while the remaining 60% of our refined products tariffs are either subject to regulations by the states in which we

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operate or are deemed competitive by the FERC, in which case these rates can be adjusted at our discretion based on market factors. The FERC-approved indexing method to be used for the five-year period beginning in July 2016 is the annual change in the producer price index for finished goods ("PPI-FG") plus 1.23%. Based on this indexing methodology, we anticipate decreasing our tariff rates by approximately 2% for the 40% of our tariffs that are subject to this indexing methodology. For the remaining 60% of our tariffs that are deemed competitive, we generally expect to increase these tariff rates; however, we have not completed our evaluation of these markets so the amount of tariff increases is not known at this time.

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.

Board of Director and Senior Management Changes. On November 30, 2015, James C. Kempner, a member of our general partner's board of directors, resigned from the board. Mr. Kempner's decision to resign from the board was not due to any disagreement with us on any matter relating to our operations, policies or practices.

On February 15, 2016, Brett C. Riley, Senior Vice President - Business Development, announced his resignation effective April 1, 2016 to pursue other interests. Mr. Riley has worked with Magellan and its predecessors since 1992. Michael J. Aaronson has been elected by our general partner's board of directors as Senior Vice President - Business Development upon Mr. Riley's departure. Mr. Aaronson currently serves as Vice President - Crude Oil, Business Development and joined Magellan in 2011.

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.

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, which will generally be made over the next one to ten years, 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, 2013 were as follows (in millions):

Balance 12/31/13	2014 Accruals	Expenditures	Balance 12/31/14	2015 Accruals	Expenditures	Balance 12/31/15
$38.5	$5.8	$(8.0)	$36.3	$6.3	$(11.2)	$31.4

During 2014, we increased our environmental liability accruals by $5.8 million. Of this amount, $0.6 million related to product releases that occurred during 2014 and $5.2 million related to historical releases. At December 31, 2014, we had recognized $5.1 million of receivables from insurance carriers associated with environmental claims.

During 2015, we increased our environmental liability accruals by $6.3 million. Of this amount, $5.6 million related to product releases that occurred during 2015 and $0.7 million related to historical releases. At December 31, 2015, we had recognized $2.6 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.

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	$ (2,873)	$ 3,913	$ (21,848)	$ 26,504
Expected long-term rate of return on plan assets	$ (1,238)	$ 1,599	$ —	$ —
Rate of compensation increase	$ 3,276	$ (2,763)	$ 13,245	$ (12,983)
Other postretirement benefits:				
Discount rate	$ (118)	$ 145	$ (1,268)	$ 1,596
Assumed health care cost trend rate	$ 80	$ (74)	$ 473	$ (435)

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% Decrease	1% Increase
Projected return on assets	$133	$(111)
Rate of compensation increase	$(4,058)	$4,135

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 debt 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 debt 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.

Valuation of Assets
The application of business combination and impairment accounting requires us to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires us to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. We record intangible assets separately from goodwill and amortize intangible assets with finite lives over their estimated useful life as determined by management. We do not amortize goodwill or intangible assets with indefinite lives but instead periodically assess these for impairment.

For all material acquisitions, we engage the services of an independent appraiser to assist us in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of our management. We base our estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management’s assumptions, which would not reflect unanticipated events and circumstances that may occur.

Goodwill and Impairment of Long-Lived Assets

Goodwill. At December 31, 2014 and 2015, we had recognized goodwill of $53.3 million. Goodwill resulting from a business combination is not subject to amortization; however, we test goodwill for impairment annually or more frequently when indicators of impairment exist. As required by Accounting Standards Codification ("ASC") 350, Goodwill and Other, we test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. For 2015, we performed a qualitative assessment to determine whether the fair value of our reporting units was more likely than not less than their respective carrying amounts. Our evaluation consisted of assessing the general impact of how a number of different elements would affect the fair value of our reporting units, including the current and projected future earnings of our reporting units, our capitalization, our current slate of capital projects, the growth in the distributions we pay to our unitholders, current and future interest rates and the impact of lower commodity prices on our earnings and the acquisition markets. Our qualitative assessment indicated that there was no need to conduct further quantitative testing for goodwill impairment and our analysis did not reflect any reporting units at risk. Different judgments from those we used in our qualitative analysis could result in the requirement to perform a quantitative goodwill impairment analysis. Results from that quantitative analysis could use projections and estimates different from those others might use, which could result in the recognition of an impairment loss. Any such impairment losses recognized could be material to our results of operations. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for our refined products and crude oil segments. Based on our assessments at December 31, 2013, 2014 and 2015, we did not record a goodwill impairment for any of these years.

Impairment of Long-Lived Assets. As prescribed by ASC 360-10-05, Property, Plant and Equipment-General-Impairment or Disposal of Long-Lived Assets, we assess property, plant and equipment ("PP&E") for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets 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. Impairments recognized during 2013, 2014 and 2015 were not material.

An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and impairment calculations is not practicable, given the broad range of our PP&E 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.

New Accounting Pronouncements

See Note 2 – Summary of Significant Accounting Policies of the consolidated financial statements included in Item 8 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," "projects," "scheduled," "should" 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;
- decreases 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 and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, as well as regulatory developments or other trends that could affect demand for our services;
- 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 implemented by the Federal Energy Regulatory Commission, 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, operational hazards, equipment failures, system failures or unforeseen interruptions;
- not being adequately insured or having losses that exceed our insurance coverage;
- our ability to obtain insurance and to manage the increased cost of available insurance;
- 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 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 that govern product quality specifications or renewable fuel obligations that could impact our ability to produce gasoline volumes through our blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we or our customers are or 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 or our subsidiaries;
- 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 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.

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 are exposed to market risk through changes in commodity prices and interest rates. We have established policies to monitor and control these market risks. We also enter into derivative agreements to help manage our exposure to commodity price and interest rate risks. We do not enter into derivative agreements for speculative purposes.

Commodity Price Risk

Our commodity price risk primarily arises from our butane blending and fractionation activities, from managing product imbalances associated with our refined products and crude oil pipelines and certain crude inventories. We use derivatives such as forward physical contracts, NYMEX petroleum products contracts and butane 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, 2015, we had commitments under forward purchase and sale contracts used in our butane blending and fractionation activities as follows (in millions):

	Total	< 1 Year	1 – 3 Years
Forward purchase contracts – notional value	$79.8	$72.9	$6.9
Forward purchase contracts – barrels	2.5	2.3	0.2
Forward sales contracts – notional value	$0.5	$0.5	$—
Forward sales contracts – barrels[(1)]	—	—	—

[(1)]Less than 0.1 million barrels.

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from activities in which we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment, and we designate and account for these contracts as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We also use NYMEX contracts to hedge against changes in the price of butane that we expect to purchase in future periods. At December 31, 2015, we had open NYMEX contracts representing 5.2 million barrels of petroleum products we expect to sell in the future. Additionally, we had open NYMEX contracts for 0.9 million barrels of butane we expect to purchase in the future. At December 31, 2015, the fair value of our open NYMEX contracts was an asset of $42.7 million.

At December 31, 2015, open NYMEX contracts representing 4.5 million barrels of petroleum products we expect to sell in the future did not qualify for hedge accounting treatment. A $10.00 per barrel increase in the price of these NYMEX contracts for the related petroleum products would result in a $45.0 million decrease in our operating profit and a $10.00 per barrel decrease in the price of these NYMEX contracts would result in a $45.0 million increase in our operating profit.

At December 31, 2015, we had open NYMEX contracts representing 0.9 million barrels of butane we expect to purchase in the future. Relative to these agreements, a $10.00 per barrel increase in the price of butane would result in a $9.0 million increase in our operating profit and a $10.00 per barrel decrease in the price of butane would result in a $9.0 million decrease in our operating profit.

The increases or decreases in operating profit we recognize from our open NYMEX forward sales and price swap contracts 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 occur. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure and the resulting hedges may not eliminate all price risks.

Interest Rate Risk
Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk.

During 2015, we entered into $200.0 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 2016. The fair value of these contracts at December 31, 2015 was an asset of $1.5 million. We account for these agreements as cash flow hedges. A 0.125% decrease in the interest rates would result in a decrease in the fair value of these contracts of approximately $2.3 million. A 0.125% increase in the interest rates would result in an increase in the fair value of these contracts of approximately $2.2 million.

At December 31, 2015, we had $280.0 million of commercial paper notes outstanding which represents variable rate debt. We can issue up to $1.0 billion of commercial paper, limited by the amounts available under our revolving credit facility. Considering the amount of commercial paper borrowings outstanding at December 31, 2015, our annual interest expense would change by approximately $0.4 million if rates charged by our commercial paper lenders changed by 0.125%.

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. Internal control over financial reporting is defined as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management and other personnel, 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 and 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 our assets; (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 our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention and timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on our financial statements.

Management believes that the design and operation of our internal control over financial reporting at December 31, 2015 were effective.

We assessed our internal control system using the criteria for effective internal control over financial reporting described in “Internal Control-Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“2013 COSO” criteria). As of December 31, 2015, based on the results of our assessment, management believed that we had no material weaknesses in internal control over our financial reporting. We maintained effective internal control over financial reporting as of December 31, 2015 based on 2013 COSO 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, 2015. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2015, 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

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

We have audited Magellan Midstream Partners, L.P.’s internal control over financial reporting as of December 31, 2015, 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). Magellan Midstream Partners, L.P.’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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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.

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

In our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2015 and 2014, 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, 2015, and our report dated February 19, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 19, 2016

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2015 and 2014, 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, 2015. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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), Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2015, 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 19, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 19, 2016

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

	Year Ended December 31,		
	2013	2014	2015
Transportation and terminals revenue	$1,188,452	$1,459,267	$1,544,746
Product sales revenue	744,669	878,974	629,836
Affiliate management fee revenue	14,609	22,111	13,871
Total revenue	1,947,730	2,360,352	2,188,453
Costs and expenses:			
Operating	396,194	500,901	525,902
Cost of product sales	578,029	594,585	447,273
Depreciation and amortization	142,230	161,741	166,812
General and administrative	132,496	148,288	151,329
Total costs and expenses	1,248,949	1,405,515	1,291,316
Earnings of non-controlled entities	6,275	19,394	66,483
Operating profit	705,056	974,231	963,620
Interest expense	132,887	145,862	158,895
Interest income	(342)	(1,540)	(1,276)
Interest capitalized	(14,339)	(22,803)	(14,442)
Other expense (income)	—	8,573	(1,015)
Income before provision for income taxes	586,850	844,139	821,458
Provision for income taxes	4,613	4,620	2,336
Net income	$582,237	$839,519	$819,122
Basic net income per limited partner unit	$2.57	$3.69	$3.60
Diluted net income per limited partner unit	$2.56	$3.69	$3.59
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	226,829	227,260	227,550
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	227,094	227,626	227,888

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2013	2014	2015
Net income	$582,237	$839,519	$819,122
Other comprehensive income:			
Derivative activity:			
Net loss on cash flow hedges(1)	(4,744)	(30,090)	(14,904)
Reclassification of net loss (gain) on cash flow hedges to income(1)	4,245	(124)	1,365
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial (loss) gain(2)	14,089	(33,937)	(8,359)
Plan amendment(2)	—	—	3,610
Amortization of prior service credit(2)	(3,405)	(3,680)	(3,713)
Amortization of actuarial loss(2)	5,369	3,986	7,191
Settlement cost(2)	—	1,809	—
Total other comprehensive income (loss)	15,554	(62,036)	(14,810)
Comprehensive income	$597,791	$777,483	$804,312

(1) See Note 13–Derivative Financial Instruments for details of the amount of gain/loss recognized in accumulated other comprehensive loss ("AOCL") on derivatives and the amount of gain/loss reclassified from AOCL into income.
(2) See Note 10–Employee Benefit Plans for additional detail of the changes in employee benefit plan assets and benefit obligations that are recognized in other comprehensive income (loss).

See notes to consolidated financial statements.

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

	December 31, 2014	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$17,063	$28,731
Trade accounts receivable	84,465	83,893
Other accounts receivable	15,711	12,701
Inventory	157,762	130,868
Energy commodity derivatives contracts, net	87,151	39,243
Energy commodity derivatives deposits	6,184	—
Other current assets	34,331	43,418
Total current assets	402,667	338,854
Property, plant and equipment	5,533,935	6,166,766
Less: accumulated depreciation	1,204,601	1,347,537
Net property, plant and equipment	4,329,334	4,819,229
Investments in non-controlled entities	613,867	765,628
Long-term receivables	28,611	20,374
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $11,526 and $13,709 at December 31, 2014 and 2015, respectively)	4,573	1,856
Tank bottoms	42,585	27,533
Other noncurrent assets	26,512	14,833
Total assets	$5,501,409	$6,041,567
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$97,131	$104,094
Accrued payroll and benefits	48,298	51,764
Accrued interest payable	45,973	51,296
Accrued taxes other than income	47,888	51,587
Environmental liabilities	10,564	15,679
Deferred revenue	71,142	81,627
Accrued product purchases	44,355	31,339
Energy commodity derivatives contracts, net	5,413	—
Energy commodity derivatives deposits	84,463	24,252
Current portion of long-term debt	—	250,335
Other current liabilities	80,928	51,099
Total current liabilities	536,155	713,072
Long-term debt, net	2,967,019	3,189,287
Long-term pension and benefits	75,155	77,551
Other noncurrent liabilities	29,069	24,162
Environmental liabilities	25,778	15,759
Commitments and contingencies		
Partners' capital:		
	1,949,773	2,118,086

Limited partner unitholders (227,068 units and 227,427 units outstanding at December 31, 2014 and 2015, respectively)		
Accumulated other comprehensive loss	(81,540)	(96,350)
Total partners’ capital	1,868,233	2,021,736
Total liabilities and partners' capital	$5,501,409	$6,041,567

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2013	2014	2015
Operating Activities:			
Net income	$582,237	$839,519	$819,122
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	142,230	161,741	166,812
Loss on sale and retirement of assets	7,835	7,223	7,871
Earnings of non-controlled entities	(6,275)	(19,394)	(66,483)
Distributions from investments in non-controlled entities	2,494	3,086	66,285
Equity-based incentive compensation expense	24,083	27,284	24,245
Settlement cost, amortization of prior service credit and actuarial loss	1,964	2,115	3,478
Changes in components of operating assets and liabilities (Note 3)	18,508	85,727	48,362
Net cash provided by operating activities	773,076	1,107,301	1,069,692
Investing Activities:			
Additions to property, plant and equipment, net[(1)]	(421,435)	(363,250)	(621,151)
Proceeds from sale and disposition of assets	3,610	10,780	3,371
Acquisition of assets	(22,506)	(75,000)	—
Acquisition of business	(192,000)	—	(54,678)
Investments in non-controlled entities	(250,495)	(408,001)	(152,466)
Distributions in excess of earnings of non-controlled entities	780	5,487	14,155
Net cash used by investing activities	(882,046)	(829,984)	(810,769)
Financing Activities:			
Distributions paid	(475,461)	(568,806)	(662,948)
Net commercial paper borrowings (repayments)	—	296,942	(16,981)
Borrowings under long-term notes	298,680	257,713	499,589
Payments on notes	—	(250,000)	—
Debt issuance costs	(4,849)	(2,912)	(6,223)
Net payment on financial derivatives	(184)	(3,613)	(42,908)
Settlement of tax withholdings on equity-based incentive compensation	(12,259)	(14,813)	(17,784)
Net cash used by financing activities	(194,073)	(285,489)	(247,255)
Change in cash and cash equivalents	(303,043)	(8,172)	11,668
Cash and cash equivalents at beginning of period	328,278	25,235	17,063
Cash and cash equivalents at end of period	$25,235	$17,063	$28,731
Supplemental non-cash investing and financing activities:			
Contribution of property, plant and equipment to a non-controlled entity	$—	$—	$13,252
Issuance of limited partner units in settlement of equity-based incentive plan awards	$6,404	$7,315	$8,045
(1) Additions to property, plant and equipment	$(383,757)	$(366,445)	$(623,289)
Changes in accounts payable and other current liabilities related to capital expenditures	(37,678)	3,195	2,138
Additions to property, plant and equipment, net	$(421,435)	$(363,250)	$(621,151)

See notes to consolidated financial statements.

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

	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Total Partners' Capital
Balance, January 1, 2013	$ 1,550,760	$ (35,058)	$ 1,515,702
Comprehensive income:			
Net income	582,237	—	582,237
Total other comprehensive income	—	15,554	15,554
Total comprehensive income	582,237	15,554	597,791
Distributions	(475,461)	—	(475,461)
Equity-based incentive compensation expense	15,532	—	15,532
Issuance of limited partner units in settlement of equity-based incentive plan awards	6,404	—	6,404
Settlement of tax withholdings on equity-based incentive compensation	(12,259)	—	(12,259)
Other	(267)	—	(267)
Balance, December 31, 2013	1,666,946	(19,504)	1,647,442
Comprehensive income:			
Net income	839,519	—	839,519
Total other comprehensive loss	—	(62,036)	(62,036)
Total comprehensive income (loss)	839,519	(62,036)	777,483
Distributions	(568,806)	—	(568,806)
Equity-based incentive compensation expense	19,963	—	19,963
Issuance of limited partner units in settlement of equity-based incentive plan awards	7,315	—	7,315
Settlement of tax withholdings on equity-based incentive compensation	(14,813)	—	(14,813)
Other	(351)	—	(351)
Balance, December 31, 2014	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
Settlement of tax withholdings on equity-based incentive compensation	(17,784)	—	(17,784)
Other	(370)	—	(370)
Balance, December 31, 2015	$ 2,118,086	$ (96,350)	$ 2,021,736

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. We are a Delaware limited partnership and our 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 our 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, 2015, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, comprised of our 9,500 mile refined products pipeline system with 52 terminals as well as 28 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,700 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 22 million barrels, of which 14 million are used for leased 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 increasingly 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.

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

2. Summary of Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include our refined products, crude oil and marine storage segments. We consolidated 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 have control. We have eliminated all intercompany transactions.

Revision of Previously Reported Revenue and Operating Expenses. Historically, we have recorded tender deductions received from customers as an offset to operating expenses. We have concluded that these amounts should have been recorded as revenue. As a result, such amounts have been retrospectively adjusted to reflect tender deductions as transportation and terminals revenue for all periods presented herein. The adjustment impacts revenue and operating expenses as noted in the table below, but has no impact on net income, net income per unit, cash flows or distributable cash flow. We concluded that these errors were not material to any of the periods affected.

	Year ended December 31,	
	2013	2014
As reported:		
Transportation and terminals revenue	$1,138,328	$1,402,638
Costs and expenses:		
Operating	$346,070	$444,272
Effect of adjustments:		
Transportation and terminals revenue	$50,124	$56,629
Costs and expenses:		
Operating	$50,124	$56,629
As revised:		
Transportation and terminals revenue	$1,188,452	$1,459,267
Costs and expenses:		
Operating	$396,194	$500,901

Use of Estimates. The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the U.S. ("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, 2014 and 2015, 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.

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

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 market.

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

We assign asset lives based on reasonable estimates when we place an asset into service. Subsequent events could cause us to change our estimates, which would affect the future calculation of depreciation expense. The range of depreciable lives by asset category is detailed in Note 8—Property, Plant and Equipment.

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.

Investments in Non-Controlled Entities. We account for investments greater than 20% 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 $79.0 million and $76.7 million at December 31, 2014 and 2015, respectively. The amount of unamortized excess investment is primarily related to our investment in BridgeTex. We evaluate equity method investments for impairment whenever events or circumstances indicate that there is an other-than-temporary loss in value of the investment. In the event that we determine that the loss in value of an investment is other-than-temporary, we would record a charge to earnings to adjust the carrying value to fair value. We recognized no equity investment impairments during 2013, 2014 and 2015.

Goodwill and Other Intangible Assets. Goodwill resulting from a business combination is not subject to amortization. We test goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

We amortize other intangible assets over their estimated useful lives of 5 years up to 25 years. The weighted-average asset life of our other intangible assets at December 31, 2015 was approximately 6 years. We adjust the useful lives of our other intangible assets if events or circumstances indicate there has been a change in the remaining useful lives. We eliminate from our balance sheets the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. We review our other intangible assets for impairment whenever events or changes in circumstances indicate we should assess the recoverability of the carrying amount of the intangible asset. We recognized no impairments for other intangible assets in 2013, 2014 and 2015.

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

Tank Bottoms. A contract we have with a customer at our crude oil terminal in Cushing, Oklahoma requires us to maintain a minimum volume of crude oil in the tanks they utilize at that facility. Because of this contractual requirement, the crude oil we own at that facility is not sold in the normal course of our business; therefore, we classify these crude oil barrels as a long-term asset carried at cost adjusted for gains or losses on certain derivative contracts classified as fair value hedges.

Impairment of Long-Lived Assets. We evaluate our long-lived assets of identifiable business activities, other than those held for sale, for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. We base the determination of whether impairment has occurred on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. We calculate the amount of the impairment recognized as the excess of the carrying amount of the asset over the fair value of the assets, as determined either through reference to similar asset sales or by estimating the fair value using a discounted cash flow approach.

Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Interest Capitalized. 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 5.2%, 4.9% and 4.7% for the years ended December 31, 2013, 2014 and 2015, respectively.

Pension and Postretirement Medical and Life Benefit Obligations. We sponsor three pension plans that cover substantially all of our employees, a postretirement medical and life benefit plan for certain employees and a defined contribution plan. Our pension and postretirement benefit liabilities represent the funded status of the present value of benefit obligations of these plans.

We develop pension, postretirement medical and life benefits 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 interest rates, expected investment return on plan assets, 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.

Derivative Financial Instruments. We use derivative instruments to manage market price risks associated with inventories, interest rates, our tank bottom and linefill assets and certain forecasted transactions. Our policies prohibit us from engaging in speculative trading activities. For certain physical forward commodity derivative contracts, accounting guidance provides for and we apply the normal purchase / normal sale exception, 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. For all other derivative contracts, we record the agreements on our balance sheets at fair value.

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

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 correlation and 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 change in fair value of derivative financial instruments that are not designated as a hedging instrument or that do not qualify for the normal purchase / normal sales exception is 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.

We have entered into NYMEX commodity based futures contracts to hedge against price changes on a portion of the petroleum products we expect to sell in the future and changes in the fair value of our tank bottoms and linefill. Some of these contracts have qualified as cash flow or fair value hedges, while others have not. We record the effective portion of the gains or losses for those contracts that qualify for and are designated as cash flow hedges in other comprehensive income and the ineffective portion in product sales revenue. We reclassify gains and losses from contracts that qualify as cash flow hedges from other comprehensive income to product sales revenue when the hedged transaction occurs and we terminate the derivative agreement. We record the effective portion of the gains or losses for those contracts that qualify 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 those agreements that are not designated as hedges in product sales revenue, except for those undesignated agreements that economically hedge the inventories associated with our pipeline system overages. We record the change in fair value of those agreements in operating expenses.

In addition, we have entered into NYMEX commodity based futures contracts to hedge against changes in the price of butane we expect to purchase in the future. We account for all of these agreements as economic hedges, with period changes in the fair value of these agreements recorded as adjustments to cost of product sales.

We use interest rate derivatives to help manage interest rate risk. We record any ineffectiveness on 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.

Revenue Recognition. Sales 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. Product sales revenue is recognized for products upon delivery and when the customer assumes the risks and rewards of ownership.

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

We recognize pipeline transportation revenue for crude oil shipments when our customers take possession of their product from our system. For ammonia shipments and shipments of refined products under published tariffs that combine transportation and terminalling services, we recognize revenue when our customers take possession of their product from our system. For all other 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. Our tariffs include provisions which allow us to deduct from our customer's inventory a small percentage of the products our customers transport on our pipeline systems. We refer to these product quantities as tender deductions. We receive tender deductions from our customers as consideration for product losses 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 losses may be during the delivery process. Tender deduction revenue is recognized when the transportation service is complete and is recorded at the fair value of the product received.

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. We recognize leased 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 contract services. We recognize product sales upon delivery of the product to the customer. We record back-to-back purchases and sales of refined products where we are acting as an agent to facilitate refined product sales between a supplier and a customer on a net basis.

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.

Pipeline Over/Short Product. Each period end we measure the volume of each type of product in our pipeline system, which is compared to the volumes of our customers' inventories (as adjusted for tender deductions). To the extent that the product volumes in our pipeline system exceeds the volumes of our customers' book inventories, we increase our product inventories and recognize a gain; however, to the extent the product in our pipeline system is less than our customers' book inventories, we record a liability (for product owed to our customers) and recognize a loss. The product gains and losses we recognize are recorded based on period-end product market prices, and we include those gains or losses in operating expenses on our consolidated statements of income.

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

Excise Taxes Charged to Customers. Revenues are recorded net of all amounts charged to our customers for excise taxes.

Equity-Based Incentive Compensation. The compensation committee of our general partner’s board of directors (the “compensation committee") has approved incentive awards of phantom units representing limited partner interests in us to certain employees and to independent members of our general partner’s board of directors. The phantom unit awards granted include: (i) performance-based awards which are issued to officers, managers and other key employees (“performance-based awards”), (ii) time-based awards which are issued to certain officers, managers and key employees (“time-based awards”), and (iii) performance awards which are issued to independent members of our general partner’s board of directors (“director awards”). All of the performance-based, time-based and director awards include tandem distribution equivalent rights.

We classify our performance-based and time-based unit awards as equity and we classify the director awards as liability awards. Fair value for award grants classified as equity is determined on the grant date of the award, and we recognize this value as compensation expense ratably over the requisite service period, which is the vesting period of each unit award. Because all of our outstanding unit awards contain tandem distribution equivalent rights, the per-unit fair value of our equity awards is the closing price of our limited partner units on the grant date. However, the per-unit fair value of our performance-based unit awards also includes the fair value of the market-based component of those awards. Compensation expense for our equity unit awards is calculated as the number of unit awards less estimated forfeitures, multiplied by the per unit 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. Compensation expense for our liability awards is calculated as the number of phantom units awarded, multiplied by the per unit fair value of those awards on the last day of the reporting period, less previously-recognized compensation expense.

Performance-based awards issued in 2014 and 2015 include provisions that can result in payouts to the recipients of these awards of 0% to 200% of the targeted amount of the award. Additionally, these performance-based awards are subject to a total unitholder return market performance adjustment, which could increase or decrease the payout of these awards by as much as 50%. The market performance adjustment component is based on our total unitholder return compared to the total unitholder returns of specified peer companies. Judgments and assumptions of the final award payouts are inherent in the accruals recorded for equity-based incentive compensation costs. The use of alternate judgments and assumptions could result in the recognition of different levels of equity-based incentive compensation costs.

Payouts related to time-based awards are based solely on the completion of the requisite service period by the employee. Time-based awards contain no provisions which would provide for a payout to the employee of anything other than the original number of units awarded and the associated tandem distribution equivalents.

The vesting period for both the performance-based and time-based 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. We settle performance-based and time-based awards that have vested by issuing new limited partner units, except for the associated statutory minimum tax withholding, which we settle by paying in cash. Director awards may be deferred and may be settled in cash or by issuing limited partner units. Director awards deferred prior to 2015 are paid in January of the year following the director’s death or resignation from the board of directors of our general partner.

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.

Contingencies and Environmental. 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

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

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 selective 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.

Income Taxes. We are a partnership for income tax purposes and, therefore, have not been 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 the individual partners through the allocation 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.

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, 2013, 2014 and 2015, our qualifying income met the statutory requirement.

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

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

Net Income Per Unit. We calculate basic net income per limited partner unit for each period by dividing net income by the weighted-average number of limited partner units outstanding. The difference between our actual limited partner units outstanding and our weighted-average number of limited partner units outstanding used to calculate net income per limited partner unit, is due to the impact of: (i) the phantom units issued to non-employee directors which is 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.

New Accounting Pronouncements

In September 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments, to amend the guidance for amounts that are adjusted in a merger or acquisition. This ASU eliminates the requirement that an acquirer in a business combination account for measurement-period adjustments retrospectively. Instead, an acquirer will recognize a measurement-period adjustment during the period in which it determines the amount of the adjustment. This ASU is effective for fiscal years beginning after December 15, 2015 and interim periods within those fiscal years. Our adoption of this standard is not expected to have a material impact on our results of operations, financial position or cash flows.

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 is effective for fiscal years beginning after December 15, 2016 and interim periods within those fiscal years. Our adoption of this standard will not have a material impact on our results of operations, financial position or cash flows.

In April 2015, the FASB issued ASU 2015-03, Interest: Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. Under this update, the costs for issuing debt will be included on the balance sheets as a direct deduction from the debt's value. The amendments will not affect the recognition and measurement of the costs for issuing debt. In August 2015, the FASB issued ASU 2015-15, Interest-Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements–Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015, EITF Meeting, which provides entities with the option of presenting deferred debt issuance costs related to line-of-credit arrangements as an asset, and subsequently amortizing the deferred costs over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. These amendments are required for reporting periods that begin after December 15, 2015, with early adoption permitted. We elected to adopt these amendments in the fourth quarter of 2015. Our adoption did not have a material impact on our results of operations, financial position or cash flows. See Note 12 Debt of the consolidated financial statements for additional details.

In April 2015, the FASB issued ASU 2015-04, Practical Expedient for the Measurement Date of an Employer’s Defined Benefit Obligation and Plan Assets. For an entity that has a significant event in an interim period that calls for a re-measurement of defined benefit plan assets and obligations (i.e., a partial settlement), the

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

amendments in this ASU provide a practical expedient that permits the entity to re-measure defined benefit plan assets and obligations using the month-end that is closest to the date of the significant event. This ASU is effective for reporting periods beginning after December 15, 2015. Our adoption of this standard is not expected to have a material impact on our results of operations, financial position or cash flows.

In April 2015, the FASB issued ASU 2015-05, Intangibles-Goodwill and Other-Internal-Use Software: Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. Where an entity has entered into a cloud computing arrangement, this update requires the entity to capitalize the software license element of arrangements that include a software license. Where the cloud computing arrangement does not include a software license, the arrangement is to be accounted for as a service contract. This ASU is effective for reporting periods beginning after December 15, 2015. Our adoption of this standard will not have a material impact on our results of operations, financial position or cash flows.

In January 2015, the FASB issued ASU 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates all references to and guidance concerning the classification and presentation of extraordinary items and emphasizes that the nature and effects of an event or transaction deemed unusual in nature or that is expected to occur infrequently should be disclosed on the face of the income statement as a separate component of income from continuing operations, or, alternatively, in notes to the financial statements. The new standard is effective for annual and interim periods after December 15, 2015. Early adoption is permitted. We adopted this standard on January 1, 2015. Our adoption of this ASU did not have a material impact on our results of operations, financial position or cash flows.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements–Going Concern (Subtopic 205-40): Disclosure of Uncertainties About an Entity's Ability to Continue as a Going Concern. This standard requires management to assess an entity's ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. Before this standard, no accounting guidance existed for management on when and how to assess or disclose going concern uncertainties. The amendments are effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. Early application is permitted. We adopted this standard on January 1, 2015. Our adoption of this ASU did not have a material impact on our results of operations, financial position or cash flows.

In June 2014, the FASB issued ASU 2014-12, Compensation–Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This ASU finalizes the Emerging Issues Task Force's Proposed ASU No. EITF-13D of the same name and seeks to resolve the diversity in practice that exists when accounting for share-based payments. This ASU requires that a performance target that affects vesting and can be achieved after the requisite service period to be accounted for as a performance condition. The new standard is effective for annual and interim periods after December 15, 2015, with early adoption permitted. We adopted this standard on January 1, 2015. Our adoption of this ASU did not have a material impact on our results of operations, financial position or cash flows.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which eliminates the industry-specific guidance in U.S. GAAP and produces a single, principles-based method for companies to report revenue in their financial statements. This standard requires companies to make more estimates and use more judgment than under current guidance. In addition, all companies must compile more extensive footnote disclosures about how the revenue numbers were derived. This ASU requires full retrospective, modified retrospective, or use of the cumulative effect method during the period of adoption. We have not yet determined which adoption method we will employ. In July 2015, the FASB extended the effective date of this standard from January 1, 2017 to

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January 1, 2018. Early adoption of this standard is not allowed. We are currently in the process of evaluating the impact this new standard will have on our financial statements.

In April 2014, the FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This standard will limit the number of disposals of assets that should be presented as discontinued operations to those disposals that represent a strategic shift in operations and have a major effect on the organization's operations and financial results. Expanded disclosures will be required to provide more information about the assets, liabilities, income and expenses of discontinued operations as well as significant asset disposals that do not meet the criterion for discontinued operations treatment. This ASU took effect for annual financial statements with fiscal years beginning on or after December 15, 2014. Our adoption of this ASU did not have a material impact on our results of operations, financial position or cash flows.

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2013	2014	2015
Trade accounts receivable and other accounts receivable	$(19,314)	$49,215	$3,664
Inventory	34,664	29,462	26,894
Energy commodity derivatives contracts, net of derivatives deposits	534	(7,583)	(606)
Accounts payable	2,002	(10,918)	4,107
Accrued payroll and benefits	9,809	6,055	3,466
Accrued interest payable	2,876	1,038	5,323
Accrued taxes other than income	5,485	9,094	3,699
Deferred revenue	16,793	7,978	10,485
Accrued product purchases	(9,016)	(18,678)	(13,016)
Current and noncurrent environmental liabilities	(12,247)	(2,144)	(4,904)
Other current and noncurrent assets and liabilities	(13,078)	22,208	9,250
Total	$18,508	$85,727	$48,362

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 statement of cash flows. At December 31, 2013, 2014 and 2015, the long-term pension and benefits liability was increased (decreased) by $(14.1) million, $33.9 million and $4.7 million, respectively, resulting in a corresponding increase (decrease) in AOCL. Additionally, at December 31, 2014, associated with our interest rate hedges, other current liabilities were increased by $26.5 million resulting in a corresponding increase in accumulated other comprehensive loss. The impact of our interest rate hedges at December 31, 2015 was an increase to other current assets and other current liabilities of $2.2 million and $0.7 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

4. Investments in Non-Controlled Entities

Our investments in non-controlled entities at December 31, 2015 were comprised of:

Entity	Ownership Interest
BridgeTex Pipeline Company, LLC ("BridgeTex")	50%
Double Eagle Pipeline LLC ("Double Eagle")	50%
Osage Pipe Line Company, LLC ("Osage")	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%

The fixed management fees we have recognized from BridgeTex, Osage, Powder Springs, Saddlehorn, Seabrook and Texas Frontera are reported as affiliate management fee revenue on our consolidated statements of income. In addition, we receive reimbursement from certain of our joint ventures for costs incurred during construction. During 2015, we received construction cost reimbursements of $1.2 million and $0.1 million from Saddlehorn and Powder Springs, respectively, which were recorded as reductions to costs and expenses on our consolidated statements of income.

At December 31, 2014, we recognized a liability of $2.2 million to BridgeTex primarily for pre-paid construction management fees (no liability was recognized at December 31, 2015). For the year ended December 31, 2014 and 2015, respectively, we recognized pipeline capacity lease revenue from BridgeTex of $2.6 million and $34.6 million, which we included in transportation and terminals revenue on our consolidated statements of income. We recognized a $2.6 million receivable from BridgeTex at December 31, 2014, and no receivable was outstanding at December 31, 2015.

In third quarter 2015, we purchased surplus pipe from BridgeTex for the amount of $0.6 million. We sold a portion of the pipe purchased from BridgeTex to Saddlehorn for $0.2 million.

We recognized throughput revenue from Double Eagle for the year ended December 31, 2014 and 2015, respectively, of $2.7 million and $3.4 million, which we included in transportation and terminals revenue on our consolidated statements of income. At December 31, 2014 and 2015, respectively, we recognized a $0.3 million and $0.2 million trade accounts receivable from Double Eagle.

The financial results from Texas Frontera are included in our marine storage segment, the financial results from BridgeTex, Double Eagle, 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 as earnings/losses of non-controlled entities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

A summary of our investments in non-controlled entities follows (in thousands):

	BridgeTex	All Others	Consolidated
Investments at December 31, 2014	$489,348	$124,519	$613,867
Additional investment	16,605	149,113	165,718
Earnings of non-controlled entities:			
Proportionate share of earnings	60,446	8,826	69,272
Amortization of excess investment and capitalized interest	(2,039)	(750)	(2,789)
Earnings of non-controlled entities	58,407	8,076	66,483
Less:			
Distributions of earnings from investments in non-controlled entities	58,407	7,878	66,285
Distributions in excess of earnings of non-controlled entities	10,686	3,469	14,155
Investments at December 31, 2015	$495,267	$270,361	$765,628

Summarized financial information of our non-controlled entities follows (in thousands):

	December 31, 2014			December 31, 2015		
	BridgeTex	All Others	Consolidated	BridgeTex	All Others	Consolidated
Current assets	$66,409	$11,032	$77,441	$46,856	$111,272	$158,128
Noncurrent assets	821,323	210,587	1,031,910	809,676	573,718	1,383,394
Total assets	$887,732	$221,619	$1,109,351	$856,532	$684,990	$1,541,522
Current liabilities	$71,066	$4,724	$75,790	$23,570	$125,661	$149,231
Noncurrent liabilities	94	1,783	1,877	462	7,257	7,719
Total liabilities	$71,160	$6,507	$77,667	$24,032	$132,918	$156,950
Equity	$816,572	$215,112	$1,031,684	$832,500	$552,072	$1,384,572

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	Year Ended December 31, 2013		
	BridgeTex	All Others	Consolidated
Revenue	$—	$29,333	$29,333
Net income (loss)	$(40)	$13,571	$13,531

	Year Ended December 31, 2014		
	BridgeTex	All Others	Consolidated
Revenue	$49,200	$34,856	$84,056
Net income	$30,696	$10,583	$41,279

	Year Ended December 31, 2015		
	BridgeTex	All Others	Consolidated
Revenue	$200,214	$46,627	$246,841
Net income	$120,890	$17,567	$138,457

5. Business Combinations and Asset Acquisition

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.

2013 Business Combination. During 2013, we acquired certain refined petroleum products pipelines and terminals from Plains All American Pipeline, L.P. We have accounted for this acquisition as a business combination under the acquisition method of accounting in accordance with ASC 805, Business Combinations. The acquisition was completed in two parts, as follows:

- New Mexico/Texas System. In July 2013, we acquired approximately 250-miles of common carrier pipeline that transports refined petroleum products from El Paso, Texas north to Albuquerque, New Mexico and transports products south to the United States–Mexico border for delivery within Mexico via a third-party pipeline for $57.0 million. We funded this acquisition with cash on hand.

- Rocky Mountain System. In November 2013, we acquired approximately 550 miles of common carrier pipeline that distributes refined petroleum products in Colorado, South Dakota and Wyoming for $135.0 million. The system includes four terminals with nearly 1.7 million barrels of storage. We funded this acquisition primarily with proceeds from our $300.0 million debt offering we completed in October 2013.

The final purchase price and assessment of the fair value of the assets acquired and liabilities assumed in the business combination we completed during 2013 were as follows (in thousands):

Purchase price allocation:	$192,000

Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$192,422
Other current assets	2,048
Current environmental liabilities	(2,470)
Total	$192,000

The following amounts from this business combination were included in our operating results for the year ending December 31, 2013 (in thousands):

Revenue	$12,661
Operating profit	$6,400

These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2013 or the results that will be attained in the future (in thousands).

	Year Ended December 31, 2013	
	As Reported	Pro Forma
Revenue	$1,947,730	$1,974,440
Net income	$582,237	$588,583

Significant pro forma adjustments include historical results of the acquired assets and our calculation of G&A expense, depreciation expense and interest expense on borrowings necessary to finance this acquisition. Acquisition and start-up costs related to the assets acquired totaling $2.8 million were recorded to operating expenses during 2013.

Goodwill resulting from a business combination is not subject to amortization. During the years ended December 31, 2013, 2014 and 2015, we tested goodwill for impairment and concluded no change to the carrying amount of goodwill was required.

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2014 Asset Acquisition.

In November 2014, in connection with Oxy's sale of its ownership interest in BridgeTex to a third party, we acquired from a subsidiary of Oxy its ownership interest in a 40-mile crude oil pipeline that extends from our East Houston, Texas terminal to Texas City, Texas, and 1.4 million barrels of crude oil tankage and related infrastructure at the East Houston, Texas terminal for $75.0 million. At the time of this acquisition, construction of the crude oil storage tankage was complete; however, only a portion of the pipeline construction from East Houston to Texas City, Texas had been completed. Following this transaction, our ownership in these assets was 100%. Concurrent with this transaction, BridgeTex entered into a long-term lease agreement for capacity on our Houston-area crude oil distribution system.

6. Inventory
Inventory at December 31, 2014 and 2015 was as follows (in thousands):

	December 31,	
	2014	2015
Refined products	$67,055	$57,455
Liquefied petroleum gases	37,642	17,954
Transmix	36,867	21,297
Crude oil	10,015	28,385
Additives	6,183	5,777
Total inventory	$157,762	$130,868

During 2014, we recorded a lower-of-average-cost-or-market adjustment of $39.3 million combined related to our fractionation and butane blending inventories. During 2015, we recorded a lower-of-average-cost-or-market adjustment of $5.0 million combined related to our fractionation and crude oil inventories.

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 from mark-to-market adjustments from NYMEX contracts. See Note 13 – Derivative Financial Instruments for a discussion of our commodity hedging strategies and how our NYMEX contracts impact product sales revenue. All of the petroleum products inventory we physically sell associated with our butane blending and fractionation activities, as well as the barrels from product gains we obtain from our independent and marine terminals, are reported as product sales revenue on our consolidated statements of income. The physical sale of the petroleum products inventory from product gains obtained from our pipeline operations and related activities from terminals physically connected to our pipeline system are reported as adjustments to operating expense.

For the years ended December 31, 2013, 2014 and 2015, product sales revenue included the following (in thousands):

	Year Ended December 31,		
	2013	2014	2015
Physical sale of refined products	$755,266	$733,654	$561,410
Change in value of NYMEX contracts	(10,597)	145,320	68,426
Total product sales revenue	$744,669	$878,974	$629,836

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

8. Property, Plant and Equipment and Other Intangibles

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

	December 31,		Estimated Depreciable Lives
	2014	2015	
Construction work-in-progress	$314,349	$476,662	
Land and rights-of-way	243,576	275,277	
Buildings	81,657	88,641	10 to 56 years
Storage tanks	1,538,891	1,684,430	10 to 40 years
Pipeline and station equipment	2,083,204	2,249,067	10 to 69 years
Processing equipment	1,103,454	1,217,492	3 to 56 years
Other	168,804	175,197	3 to 48 years
Property, Plant and Equipment, Gross	$5,533,935	$6,166,766	

Other includes total interest capitalized on construction in progress as of December 31, 2014 and 2015 of $35.8 million and $31.4 million, respectively. Depreciation expense for the years ended December 31, 2013, 2014 and 2015 was $136.4 million, $159.0 million and $164.1 million, respectively.

We amortize other intangible assets over their estimated useful lives of 5 years up to 25 years. The weighted average asset life of our other intangible assets at December 31, 2015 was approximately 6 years. We adjust the useful lives of our other intangible assets if events or circumstances indicate there has been a change in the remaining useful lives. We eliminate from our balance sheets the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. During the years ended December 31, 2013, 2014 and 2015 amortization of other intangible assets was $6.0 million, $2.7 million and $2.7 million, respectively. No material impairments of intangible assets were recorded during these same annual periods.

9. Major Customers and Concentration of Risks

Major Customers. One customer accounted for 8%, 12% and 6% of our consolidated total revenue in 2013, 2014 and 2015, respectively. No other customer accounted for more than 10% of our consolidated revenues during these years. The majority of revenue from this customer resulted from sale of refined products that were generated in connection with our butane blending and fractionation activities, which are activities conducted by our refined products segment. We believe that other companies would purchase the petroleum products from us if this customer were unable or unwilling to do so.

Concentration of Risks. We transport, store and distribute refined products for refiners, marketers, traders and end users of those products. We derive the major concentration of our revenue and trade receivables from activities conducted 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, 2015, we had 1,640 employees, 903 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 25% of the 903 employees are represented by the United Steel Workers ("USW") and are covered by a collective bargaining agreement that expires January 31, 2019. At December 31, 2015, 98 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. The labor force of 170 employees assigned to our marine storage segment at December 31, 2015 was primarily located in the Gulf and East Coast regions of the U.S. Approximately 16% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires October 31, 2016.

10. Employee Benefit Plans

We sponsor two union pension plans that cover certain union employees ("USW plan" and "IUOE plan," collectively, the "Union plans") and a pension plan for all non-union employees ("Salaried plan"), a postretirement benefit plan for certain employees and a defined contribution plan.

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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 for the years ended December 31, 2014 and 2015 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2014	2015	2014	2015
Change in benefit obligation:				
Benefit obligation at beginning of year	$142,310	$190,663	$10,418	$12,446
Service cost	13,400	18,890	227	243
Interest cost	6,675	7,754	506	438
Plan participants’ contributions	—	—	210	199
Plan amendment	—	(3,610)	—	—
Actuarial loss (gain)	37,934	574	1,951	(579)
Benefits paid	(4,196)	(4,680)	(866)	(1,433)
Settlement payments	(5,460)	—	—	—
Benefit obligation at end of year	190,663	209,591	12,446	11,314
Change in plan assets:				
Fair value of plan assets at beginning of year	100,556	127,267	—	—
Employer contributions	24,056	20,482	656	1,234
Plan participants’ contributions	—	—	210	199
Actual return on plan assets	12,311	(327)	—	—
Benefits paid	(4,196)	(4,680)	(866)	(1,433)
Settlement payments	(5,460)	—	—	—
Fair value of plan assets at end of year	127,267	142,742	—	—
Funded status at end of year	$(63,396)	$(66,849)	$(12,446)	$(11,314)
Accumulated benefit obligation	$137,851	$148,906		

The amounts included in pension benefits in the previous table combine the Union plans with the Salaried plan. At December 31, 2014, the fair value of each of the pension plans' assets was less than the fair values of the respective accumulated benefit obligations. At December 31, 2015, the USW and Salaried plans had a combined accumulated benefit obligation of $146.8 million, which exceeded the combined fair value of the plans' assets of $140.6 million.

The 2014 actuarial loss of $37.9 million was due primarily to the impact of decreases in the discount rate used to calculate the benefit obligation, combined with a change to the mortality rates using RP-2014 mortality tables.

The salaried and USW plans were amended effective January 1, 2016 to adjust the benefit calculation from a traditional final average pay formula to a cash balance formula for certain participants. We accounted for this change as a negative plan amendment which resulted in a reduction of our pension liability of $3.6 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

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

	Pension Benefits		Other Postretirement Benefits	
	2014	2015	2014	2015
Amounts recognized in consolidated balance sheets:				
Current accrued benefit cost	$—	$—	$687	$612
Long-term pension and benefits	63,396	66,849	11,759	10,702
	63,396	66,849	12,446	11,314
Accumulated other comprehensive loss:				
Net actuarial loss	(63,257)	(65,889)	(8,744)	(7,280)
Prior service credit	—	3,610	7,048	3,335
	(63,257)	(62,279)	(1,696)	(3,945)
Net amount of liabilities and accumulated other comprehensive loss recognized in consolidated balance sheets	$139	$4,570	$10,750	$7,369

Net periodic benefit expense for the years ended December 31, 2013, 2014 and 2015 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2013	2014	2015	2013	2014	2015
Components of net periodic pension and postretirement benefit expense:						
Service cost	$13,901	$13,400	$18,890	$288	$227	$243
Interest cost	5,368	6,675	7,754	412	506	438
Expected return on plan assets	(6,228)	(6,363)	(8,037)	—	—	—
Amortization of prior service cost (credit)	307	33	—	(3,712)	(3,713)	(3,713)
Amortization of actuarial loss	4,334	3,071	6,306	1,035	915	885
Settlement cost(1)	—	1,809	—	—	—	—
Net periodic expense (credit)	$17,682	$18,625	$24,913	$(1,977)	$(2,065)	$(2,147)

(1) Eleven participants took a lump sum distribution from the USW plan in 2014, resulting in a pension settlement cost of $1.8 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Other changes in plan assets and benefit obligations recognized in other comprehensive loss during 2014 and 2015 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2013	2014	2015	2013	2014	2015
Beginning balance	$(52,239)	$(36,184)	$(63,257)	$3,055	$3,053	$(1,696)
Net actuarial gain (loss)	11,414	(31,986)	(8,938)	2,675	(1,951)	579
Plan amendment	—	—	3,610	—	—	—
Amortization of prior service cost (credit)	307	33	—	(3,712)	(3,713)	(3,713)
Amortization of actuarial loss	4,334	3,071	6,306	1,035	915	885
Settlement cost	—	1,809	—	—	—	—
Amount recognized in other comprehensive loss	16,055	(27,073)	978	(2)	(4,749)	(2,249)
Ending balance	$(36,184)	$(63,257)	$(62,279)	$3,053	$(1,696)	$(3,945)

We match our employees' qualifying contributions to our defined contribution plan, resulting in expense to us. Expenses related to the defined contribution plan were $7.1 million, $8.3 million and $8.9 million in 2013, 2014 and 2015, respectively.

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 percent 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 2016 are $4.9 million and $(0.2) million, respectively. The estimated net actuarial loss and prior service credit for the other defined benefit postretirement plan that will be amortized from AOCL into net periodic benefit cost in 2016 are $0.7 million and $(3.3) million, respectively.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2014 and 2015 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2015	2014	2015
Discount rate—Salaried plan	3.91%	3.95%	n/a	n/a
Discount rate—USW plan	3.56%	3.82%	n/a	n/a
Discount rate—IUOE plan	3.93%	4.03%	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	3.66%	4.00%
Rate of compensation increase—Salaried plan	5.00%	*	n/a	n/a
Rate of compensation increase—USW plan	3.50%	3.50%	n/a	n/a
Rate of compensation increase—IUOE plan	5.00%	5.00%	n/a	n/a

*The 2015 rate of compensation increase assumption 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 for the years ended December 31, 2013, 2014 and 2015 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2013	2014	2015	2013	2014	2015
Discount rate—Salaried plan	4.00%	4.89%	3.91%	n/a	n/a	n/a
Discount rate—USW plan	3.39%	4.07%	3.56%	n/a	n/a	n/a
Discount rate—IUOE plan	3.99%	4.89%	3.93%	n/a	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	n/a	3.58%	4.52 %	3.66 %
Rate of compensation increase—Salaried plan	5.00%	5.00%	5.50%	n/a	n/a	n/a
Rate of compensation increase—USW plan	3.50%	3.50%	3.50%	n/a	n/a	n/a
Rate of compensation increase—IUOE plan	5.00%	5.00%	5.00%	n/a	n/a	n/a
Expected rate of return on plan assets—Salaried plan	6.80%	6.00%	6.00%	n/a	n/a	n/a
Expected rate of return on plan assets—USW plan	6.80%	6.00%	6.00%	n/a	n/a	n/a
Expected rate of return on plan assets—IUOE plan	6.80%	6.00%	6.00%	n/a	n/a	n/a

The 2014 discount rate for the USW plan reflects a combination of the rates prior to and after the lump sum settlement payments made during 2014.

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 2016 is 5.1% decreasing systematically to 4.3% by 2092 for pre-65 year-old participants. The health care cost trend rate assumption has an effect on the amounts reported. As of December 31, 2015, a 1.0% change in assumed health care cost trend rates would have the following effect (in thousands):

	1% Increase	1% Decrease
Change in total of service and interest cost components	$29	$27
Change in postretirement benefit obligation	$473	$435

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The fair value of the pension plan assets at December 31, 2014 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	$3,050	$3,050	$—	$—
Mid-cap fund	3,025	3,025	—	—
Large-cap fund	22,760	22,760	—	—
International equity fund	13,990	13,990	—	—
Fixed Income Securities[a]:				
Short-term bond funds	3,485	3,485	—	—
Intermediate-term bond funds	19,713	19,713	—	—
Long-term investment grade bond funds	56,361	56,361	—	—
Other:				
Short-term investment funds	4,603	4,603	—	—
Group annuity contract	280	—	—	280
Fair value of plan assets	$127,267	$126,987	$—	$280

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

The fair value of the pension plan assets at December 31, 2015 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	$3,492	$3,492	$—	$—
Mid-cap fund	3,495	3,495	—	—
Large-cap funds	26,304	26,304	—	—
International equity fund	16,530	16,530	—	—
Fixed Income Securities[a]:				
Short-term bond funds	3,834	3,834	—	—
Intermediate-term bond funds	18,141	18,141	—	—
Long-term investment grade bond funds	66,758	66,758	—	—
Other:				
Short-term investment funds	3,944	3,944	—	—
Group annuity contract	244	—	—	244
Fair value of plan assets	$142,742	$142,498	$—	$244

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The group annuity contract is valued at contract value, which approximates fair value as determined by the contract provider. The balance at the end of the year represents total contributions plus interest earned less benefit payments and expenses paid. The group annuity contract is guaranteed a specified return, by the Metropolitan Life Insurance Company, based on the Barclay's Capital Aggregate Bond Fund return. The fair value measurements for the group annuity contract which used significant unobservable inputs (Level 3) for the years ended December 31, 2014 and 2015 were as follows (in thousands):

	2014	2015
Beginning balance	$297	$280
Actual return on plan assets:		
Relating to assets still held at the reporting date	17	1
Purchases, issuances, sales and settlements:		
Settlements	(34)	(37)
Ending balance	$280	$244

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	Seeks 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	Seeks current income with limited price volatility through investment in primarily high quality bonds
Intermediate-term bond funds	Seeks 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	Seeks high and sustainable current income through investment primarily in long-term high grade bonds
Other:	
Short-term investment funds	Invests primarily in high quality commercial paper and government securities
Group annuity contract	Guarantees a specified return based on a specified index

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 of 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

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segment liabilities are calculated using rates defined by the Pension Protection Act of 2006. Investments are made so as to match the durations of the short and intermediate term liabilities. Additional investments are made to bring the overall investment allocation to 70% debt securities and 30% equity securities.

The target allocation and actual weighted-average asset allocation percentages at December 31, 2014 and 2015 were as follows:

	2014 Actual[(a)]	Target	2015 Actual[(a)]	Target
Equity securities	34%	30%	35%	30%
Debt securities	62%	67%	62%	67%
Other	4%	3%	3%	3%

(a) Cash contributions of $24.1 million and $20.5 million were made to the pension plans during 2014 and 2015, respectively. Amounts contributed in 2014 and 2015 in excess of benefit payments made were to be invested in debt and equity securities over a twelve-month period, with the amounts that remained uninvested as of December 31, 2014 and 2015 scheduled for investment in accordance with the target. Excluding these uninvested cash amounts, the actual allocation percentages at December 31, 2014 would have been 35% equity securities and 65% debt securities and at December 31, 2015, would have been 36% equity securities and 64% debt securities. In 2016, we will invest these uninvested cash amounts to bring the total asset allocation in line with the target allocation.

As of December 31, 2015, the benefit amounts we expect to pay through December 31, 2025 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2016	$8,300	$612
2017	$13,351	$629
2018	$14,343	$668
2019	$15,440	$722
2020	$19,944	$790
2021 through 2025	$100,735	$4,422

Contributions estimated to be paid into the plans in 2016 are $22.9 million and $0.6 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 is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase butane from subsidiaries of Targa. For the years ended December 31, 2013, 2014 and 2015, we made purchases of butane from subsidiaries of Targa of $30.4 million, $28.2 million and $25.5 million, respectively. These purchases were based on the then-current index prices. We had recognized payables to Targa of $0.9 million and $2.0 million at December 31, 2014 and 2015, 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. We received tariff revenue of $9.3 million for the period of April 23, 2015 through December 31, 2015, and have recorded a $1.3 million receivable from this customer at December 31, 2015. The tariff revenue we recognized from this customer was in the normal course of business, with rates determined in accordance with published tariffs.

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See Note 4 – Investments in Non-Controlled Entities for a discussion of transactions with our joint venture affiliates.

12. Debt

Debt at December 31, 2014 and 2015 was as follows (in thousands):

	December 31,		Weighted-Average Interest Rate for the Year Ended December 31, 2015 [1]
	2014	2015	
Commercial paper[2]	$296,942	$279,961	0.5%
$250.0 million of 5.65% Notes due 2016[3]	250,758	250,335	5.7%
$250.0 million of 6.40% Notes due 2018	257,280	255,215	5.5%
$550.0 million of 6.55% Notes due 2019	567,868	564,116	5.7%
$550.0 million of 4.25% Notes due 2021	556,304	555,362	4.0%
$250.0 million of 3.20% Notes due 2025[2]	—	249,700	3.2%
$250.0 million of 6.40% Notes due 2037	249,017	249,036	6.4%
$250.0 million of 4.20% Notes due 2042	248,406	248,437	4.2%
$550.0 million of 5.15% Notes due 2043	556,320	556,218	5.1%
$250.0 million of 4.20% Notes due 2045[2]	—	249,914	4.6%
Total debt, excluding unamortized debt issuance costs	2,982,895	3,458,294	4.7%
Unamortized debt issuance costs	(15,876)	(18,672)	
Less: current portion of long-term debt	—	250,335	
Total long-term debt	$2,967,019	$3,189,287	

(1) Weighted-average interest rate includes the amortization/accretion of discounts, premiums and gains/losses realized on historical cash flow and fair value hedges recognized as interest expense.

(2) These borrowings were outstanding for only a portion of the year ending December 31, 2015. The weighted-average interest rate for these borrowings was calculated based on the number of days the borrowings were outstanding during the noted period.

(3) These borrowings will mature in October 2016 and are included with current debt on our consolidated balance sheets at December 31, 2015.

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

In accordance with ASU No. 2015-03, Interest: Simplifying the Presentation of Debt Issuance Costs, which we adopted effective December 31, 2015, we have retrospectively presented our unamortized debt issuance costs as a direct deduction from the current value of our debt. For the year ended December 31, 2014, unamortized debt issuance costs of $15.9 million that were previously presented as an asset on our balance sheets were reclassified to long-term debt. Additionally, debt issuance costs amortization expenses of $2.4 million and $2.3 million were reclassified to interest expense for the years 2013 and 2014, respectively, as required by the new accounting standard.

The face value of our outstanding debt at December 31, 2014 and 2015 was $2.9 billion and $3.4 billion, respectively. The difference between the face value and carrying value of the debt outstanding was the unamortized portion of terminated fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the

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applicable notes over the respective lives of those notes. At December 31, 2015, maturities of our debt were as follows: $250.0 million in 2016; $0 in 2017; $250.0 million in 2018; $550.0 million in 2019; $280.0 million in 2020 (which represents the amount outstanding under our commercial paper program consistent with the maturity date of our revolving credit facility); and $2.1 billion thereafter.

2015 Debt Offerings

In March 2015, we issued $250.0 million of our 3.20% notes due 2025 in an underwritten public offering. The notes were issued at 99.871% of par. Net proceeds from this offering were $247.6 million, after underwriting discounts and offering expenses of $2.1 million. Additionally, we issued $250.0 million of our 4.20% notes due 2045 in an underwritten public offering. The notes were issued at 99.965% of par. Net proceeds from this offering were $247.3 million, after underwriting discounts and offering expenses of $2.6 million.

The net proceeds from these offerings were used to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital.

Other Debt

Revolving Credit Facilities. In October 2015, we entered into a $1.0 billion amended and restated revolving credit facility, which matures on October 27, 2020. Borrowings outstanding under the facility are classified as long-term debt on our consolidated balance sheets. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.000% to 1.625% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate from 0.100% to 0.275% depending on our credit ratings, which was 0.125% at December 31, 2015. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2015, 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.

Also in October 2015, we entered into a new $250.0 million 364-day revolving credit facility, which matures on October 25, 2016, subject to a term-out option. We may exercise the term-out option no later than 30 days prior to October 25, 2016 and elect to have all outstanding borrowings converted into a term loan due and payable on October 25, 2018, subject to the payment of a term-out fee. Borrowings under this facility are classified as current debt on our consolidated balance sheets. Borrowings under this facility are unsecured and bear interest at LIBOR, plus a spread ranging from 1.000% to 1.625% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate between 0.080% and 0.225% depending on our credit ratings, which was 0.100% at December 31, 2015. Borrowings from the credit facilities may be used for general purposes, including capital expenditures. As of December 31, 2015, there were no borrowings outstanding under this facility.

Our revolving credit facilities require 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 facilities 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, 2015.

Commercial Paper Program. The maturities of the commercial paper notes vary, but may not exceed 397 days from the date of issuance. 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 commercial paper we can issue is limited by the amounts available under our revolving credit facility up to an aggregate principal amount of $1.0 billion and, therefore, is classified as long-term debt.

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During the years ending December 31, 2013, 2014 and 2015, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $134.6 million, $149.5 million and $156.6 million, respectively.

13. Derivative Financial Instruments

Interest Rate Derivatives

We periodically enter into interest rate derivatives to economically hedge debt, interest or expected debt issuances, and we have historically designated these derivatives as cash flow or fair value hedges for accounting purposes. Adjustments resulting from discontinued hedges continue to be recognized in accordance with their historic hedging relationships.

During 2015, we entered into $200.0 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 2016. The fair values of these contracts at December 31, 2015 were recorded on our balance sheets as an other current asset of $2.2 million and an other current liability of $0.7 million with an offset to other comprehensive income. We account for these agreements as cash flow hedges.

During 2014, 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 2015. We accounted for these agreements as cash flow hedges. When we issued the $250.0 million of 4.20% notes due 2045 in first quarter 2015, we settled the associated interest rate swap agreements for a loss of $42.9 million. The loss was recorded to other comprehensive income ($26.5 million and $16.4 million recorded in 2014 and 2015, respectively) and will be recognized into earnings as an adjustment to our periodic interest expense accruals over the life 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 2015.

Also during 2014, we entered into $200.0 million of interest rate swap agreements to hedge against the variability of future interest payments on an anticipated debt issuance. We accounted for these agreements as cash flow hedges. When we issued $250.0 million of 5.15% notes due 2043 later in the first quarter of 2014, we settled the associated interest rate swap agreements for a loss of $3.6 million. The loss was recorded to other comprehensive income and is being recognized into earnings as an adjustment to our periodic interest expense accruals over the life of the associated notes. This loss was also reported as net payment on financial derivatives in the financing activities of our consolidated statements of cash flows in 2014.

During 2013, we entered into $150.0 million of Treasury lock contracts to hedge against the risk of variability of future interest payments on an anticipated debt issuance. We accounted for these contracts as cash flow hedges. These contracts were settled in fourth quarter 2013 for a loss of $0.2 million upon issuance of the associated debt. The loss was recorded to other comprehensive income and is being recognized into earnings as an adjustment to our periodic interest expense accruals over the life of the associated notes. This loss was also reported as net payment on financial derivatives in the financing activities of our consolidated statements of cash flows in 2013.

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Commodity Derivatives

Hedging Strategies

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

We account for the forward physical purchase and sale contracts we use in our butane blending and fractionation activities as normal purchases and sales. Forward contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting.

The NYMEX contracts that we enter into fall into one of three hedge categories:

Hedge Type	Hedge Purpose	Accounting Treatment
Qualifies for Hedge Accounting Treatment		
Cash Flow Hedge	To hedge the variability in cash flows related to a forecasted transaction.	The effective portion of changes in the value of the hedge is recorded to accumulated other comprehensive income/loss and reclassified to earnings when the forecasted transaction occurs. Any ineffectiveness is recognized currently in earnings.
Fair Value Hedge	To hedge against changes in the fair value of a recognized asset or liability.	The effective portion of changes in the value of the hedge is recorded as adjustments to the asset or liability being hedged. Any ineffectiveness and amounts excluded from the assessment of hedge effectiveness is recognized currently in earnings.
Does not Qualify For Hedge Accounting Treatment		
Economic Hedge	To effectively serve as either a fair value or a cash flow hedge; however, the derivative agreement does not qualify for hedge accounting treatment under ASC 815, Derivatives and Hedging.	Changes in the value of these agreements are recognized currently in earnings.

During the years ended December 31, 2014 and 2015, none of the commodity hedging contracts we entered into qualified for or were designated as cash flow hedges.

Period changes in the fair value of NYMEX agreements that are accounted for as economic hedges (other than those economic hedges of our butane purchases and our pipeline product overages as discussed below), the effective portion of changes in the fair value of cash flow hedges that are reclassified from accumulated other comprehensive income/loss and any ineffectiveness associated with hedges related to our commodity activities are recognized currently in earnings as adjustments to product sales.

We also use NYMEX contracts, which are not designated as hedges for accounting purposes, to hedge against changes in the price of butane we expect to purchase in the future. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to cost of product sales.

We hold petroleum product inventories that we obtained from overages on our pipeline systems. We use NYMEX contracts that are not designated as hedges for accounting purposes to help manage price changes related to these overage inventory barrels. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to operating expense.

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Additionally, we hold crude oil barrels that we use for operational purposes which we classify as a long-term asset on our balance sheets and which is reported as tank bottoms. We use NYMEX contracts to hedge against changes in the price of these crude oil barrels. We record the effective portion of the gains or losses for those contracts that qualify as fair value hedges as adjustments to the asset being hedged and the ineffective portions as well as amounts excluded from the assessment of hedge effectiveness as adjustments to other income or expense.

As outlined in the table below, our open NYMEX contracts at December 31, 2015 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between January 2016 and November 2017
NYMEX - Economic Hedges	4.5 million barrels of refined products and crude oil	Between January and December 2016
NYMEX - Economic Hedges	0.9 million barrels of butane	Between January and December 2016

Energy Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2015, we had received margin deposits of $24.3 million for our NYMEX contracts with our counterparties, which were recorded as a current liability under energy commodity derivatives deposits on our consolidated balance sheets. We have the right to offset the combined fair values of our open NYMEX 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 NYMEX contracts separately from the related margin deposits on our consolidated balance sheets. Additionally, we have the right to offset the fair values of our NYMEX agreements 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, 2014 and 2015 (in thousands):

	December 31, 2014				
Description	Gross Amounts of Recognized Assets	Gross Amounts of Liabilities Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets[1]	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount[3]
Energy commodity derivatives	$106,764	$(10,622)	$96,142	$(78,279)	$17,863

	December 31, 2015				
Description	Gross Amounts of Recognized Assets	Gross Amounts of Liabilities Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount[3]

			Sheets(2)		
Energy commodity derivatives	$48,367	$(5,646)	$42,721	$(24,252)	$18,469

(1) Net amount includes energy commodity derivative contracts classified as current assets, net, of $87,151, current liabilities of $5,413 and noncurrent assets of $14,404.

(2) Net amount includes energy commodity derivative contracts classified as current assets, net, of $39,243 and noncurrent assets of $3,478.

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

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Impact of Derivatives on Our Financial Statements
Comprehensive Income
The changes in derivative activity included in AOCL for the years ended December 31, 2013, 2014 and 2015 were as follows (in thousands):

	Year Ended December 31,		
Derivative Gains (Losses) Included in AOCL	2013	2014	2015
Beginning balance	$14,126	$13,627	$(16,587)
Net loss on interest rate contract cash flow hedges	(4,744)	(30,090)	(14,904)
Reclassification of net loss (gain) on cash flow hedges to income	4,245	(124)	1,365
Ending balance	$13,627	$(16,587)	$(30,126)

The following is a summary of the effect on our consolidated statements of income for the years ended December 31, 2013, 2014 and 2015 of derivatives accounted for under ASC 815-30, Derivatives and Hedging—Cash Flow Hedges, that were designated as hedging instruments (in thousands).

	Year Ended December 31, 2013			
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income: Effective Portion	Ineffective Portion
Interest rate contracts	$(184)	Interest expense	$163	$—
NYMEX commodity contracts	(4,560)	Product sales revenue	(4,408)	—
Total cash flow hedges	$(4,744)	Total	$(4,245)	$—

	Year Ended December 31, 2014			
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income: Effective Portion	Ineffective Portion
Interest rate contracts	$(30,090)	Interest expense	$(242)	$366

	Year Ended December 31, 2015			
Derivative Instrument	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
Interest rate contracts	$(14,904)	Interest expense	$(1,365)	$—

As of December 31, 2015, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $1.4 million. This amount relates to the amortization of the hedged losses on the interest rate swap contracts over the life of the related debt instruments.

During 2014 and 2015, we had open NYMEX contracts on 0.7 million barrels of crude oil that were designated as fair value hedges. Because there was no ineffectiveness recognized on these hedges, the cumulative gains at December 31, 2014 and 2015 of $13.3 million and $27.9 million, respectively, from the agreements were offset by a cumulative decrease to tank bottoms and linefill. The differential between the current spot price and forward price is excluded from the assessment of hedge effectiveness for these fair value hedges.

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During 2014 and 2015, we recognized a gain (loss) of $(8.6) million and $1.0 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.

The following table provides a summary of the effect on our consolidated statements of income for the years ended December 31, 2013, 2014 and 2015 that were not designated as hedging instruments (in thousands):

Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	Amount of Gain (Loss) Recognized on Derivative Year Ended December 31, 2013	2014	2015
NYMEX commodity contracts	Product sales revenue	$(6,189)	$145,320	$68,426
NYMEX commodity contracts	Operating expenses	(3,770)	17,818	11,819
NYMEX commodity contracts	Cost of product sales	2,682	(17,141)	(8,997)
	Total	$(7,277)	$145,997	$71,248

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 amounts included on our consolidated balance sheets that were designated as hedging instruments as of December 31, 2014 and 2015 (in thousands):

	December 31, 2014			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$360	Energy commodity derivatives contracts, net	$—
NYMEX commodity contracts	Other noncurrent assets	14,404	Other noncurrent liabilities	—
Interest rate contracts	Other current assets	—	Other current liabilities	26,478
	Total	$14,764	Total	$26,478

	December 31, 2015			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$60	Energy commodity derivatives contracts, net	$—
NYMEX commodity contracts	Other noncurrent assets	3,478	Other noncurrent liabilities	—
Interest rate contracts	Other current assets	2,179	Other current liabilities	653
	Total	$5,717	Total	$653

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The following tables provide a summary of the amounts included on our consolidated balance sheets that were not designated as hedging instruments as of December 31, 2014 and 2015 (in thousands):

	December 31, 2014			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$92,000	Energy commodity derivatives contracts, net	$10,622

	December 31, 2015			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$44,829	Energy commodity derivatives contracts, net	$5,646

See Note 19 – Fair Value Disclosures for additional details regarding our derivative contracts.

14. Leases

Leases—Lessee. We lease land, office buildings and terminal equipment at various locations to conduct our business operations. We have also entered into contracts to lease pipeline capacity, primarily to accommodate the additional barrels from our Longhorn crude oil pipeline. Several of the agreements provide for negotiated renewal options and cancellation penalties, some of which include the requirement to remove our pipeline from the property for non-performance. 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 $12.0 million, $21.0 million and $25.7 million for the years ended December 31, 2013, 2014 and 2015, respectively. Future minimum annual rentals under non-cancellable operating leases with initial or remaining terms greater than one year as of December 31, 2015, were as follows (in millions):

2016	$26.5
2017	27.5
2018	21.7
2019	11.7
2020	9.4
Thereafter	81.1
Total	$177.9

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Leases—Lessor. We have entered into capacity and storage leases 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, 2015, were as follows (in millions):

2016	$233.1
2017	202.0
2018	153.7
2019	118.2
2020	94.8
Thereafter	232.0
Total	$1,033.8

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, 2014 and 2015 was as follows (in millions):

	December 31, 2014	December 31, 2015
Total minimum lease payments receivable	$37.9	$30.7
Less: Unearned income	7.0	5.8
Recorded net investment in direct financing lease	$30.9	$24.9

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

	December 31, 2014	December 31, 2015
Current accounts receivable	$6.1	$6.4
Non-current accounts receivable	24.8	18.5
Total	$30.9	$24.9

Future minimum payments receivable under this direct financing lease for the next five years are: 2016 – $7.4 million; 2017 – $4.1 million; 2018 – $1.7 million; 2019 – $1.7 million; and 2020 – $1.7 million.

15.Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan (“LTIP”) covering certain of our employees and independent directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 9.4 million of our limited partner units. The estimated units available under the LTIP at December 31, 2015 total 1.0 million. The compensation committee of our general partner's board of directors administers our LTIP.

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Under our LTIP, the compensation committee has granted performance-based and time-based phantom unit awards. Time-based awards are subject to forfeiture by a participant if their employment is terminated for any reason other than retirement, death or disability prior to the vesting date. In addition, there are certain other employment restrictions that can result in the forfeiture of these awards. Performance-based awards are subject to forfeiture by a participant if their employment is terminated for any reason other than retirement, death or disability prior to the vesting date or for a 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. If a performance-based or time-based award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's award will be prorated based upon the completed months of employment during the vesting period, and the award will be settled shortly after the end of the vesting period. Our agreement with the award participants requires these awards to be paid in our limited partner units. Award grants under our LTIP do not have an early vesting feature except for the performance-based and time-based awards issued to our executive officers, which can vest early under certain circumstances following a change in control of our general partner.

For performance-based phantom unit awards issued prior to 2014, we based the payout calculation for 80% of the award solely on the attainment of a financial metric established by the compensation committee. We accounted for this portion of these award grants as equity. The payout calculation for the remaining 20% of the unit awards was based on both the attainment of a financial metric and the individual employee's personal performance as determined by the compensation committee. We accounted for this portion of these award grants as a liability.

The payout for the performance-based phantom unit awards issued in 2014 and 2015 is subject to the attainment of a financial metric and a market performance adjustment, with no individual employee personal performance component. The payout of the performance-based awards is based on our actual distributable cash flow excluding commodity-related activities for the last year of the 3-year vesting period as compared against established threshold, target and stretch goals. The payouts for the performance-related component of the award can range from 0% for below threshold results, up to 200% for actual results at stretch or above. The market performance adjustment component of the awards is based on our total unitholder return over the 3-year vesting period of the award in relation to the total unitholder returns of certain peer entities and can increase or decrease the calculated performance-based payout of the award by as much as 50%. We account for these awards as equity.

The payout for the time-based phantom unit awards that have been granted by the compensation committee is subject only to the participant's continued employment with us. We account for these award grants as equity.

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 include no adjustments for above-target or below-target performance and forfeitures are actual amounts through December 31, 2015.

	Equity Method Performance-Based Awards		Time-Based Awards		Liability Method Performance-Based Awards		Total Awards	
	Number of Unit	Weighted-Average Grant Date Fair Value	Number of Unit	Weighted-Average Grant Date Fair Value	Number of Unit	Weighted-Average Fair Value	Number of Unit	Weighted-Average Fair Value

	Awards		Awards		Awards		Awards	
Non-vested units - 1/1/2015	350,317	$ 62.85	46,668	$ 76.99	40,878	$ 82.66	437,863	$ 66.21
Units granted during 2015	148,028	$ 88.78	26,421	$ 81.51	—	$ —	174,449	$ 87.68
Units vested during 2015	(161,898)	$ 51.42	(444)	$ 56.42	(40,470)	$ 67.92	(202,812)	$ 54.73
Units forfeited during 2015	(23,207)	$ 81.28	(14,963)	$ 67.41	(408)	$ 67.92	(38,578)	$ 75.76
Non-vested units - 12/31/15	313,240	$ 79.64	57,682	$ 81.74	—	$ —	370,922	$ 79.97

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The table below summarizes the total non-vested unit awards granted by the compensation committee adjusted for units we estimate will be forfeited by the end of the vesting period and 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	Unit Awards Granted	Estimated Forfeitures	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:						
2014 Awards	187,371	21,662	124,283	289,992	12/31/2016	$7.0
2015 Awards	148,028	15,105	33,232	166,155	12/31/2017	9.8
Time-Based Awards:						
2016 Vesting Date	20,757	12,121	—	8,636	12/31/2016	0.2
2017 Vesting Date	51,859	4,612	—	47,247	12/31/2017	2.6
Total	408,015	53,500	157,515	512,030		$19.6

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

Weighted-Average Grant Date Fair Values

The weighted-average grant-date fair value of award grants issued during 2013, 2014 and 2015 were as follows:

	Equity Method				Liability Method	
	Performance-Based Awards		Time-Based Awards		Performance-Based Awards	
	Number of Unit Awards	Weighted-Average Grant Date Fair Value	Number of Unit Awards	Weighted-Average Grant Date Fair Value	Number of Unit Awards	Weighted-Average Fair Value
Units granted during 2013	182,798	$ 51.49	22,668	$ 53.02	45,700	$ 51.49
Units granted during 2014	187,371	$ 72.77	33,903	$ 82.86	—	$ —
Units granted during 2015	148,028	$ 88.78	26,421	$ 81.51	—	$ —

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, 2015. The vested limited partner units include adjustments for above-target performance.

Vesting Date	Vested Limited Partner Units	Fair Value of Unit Awards on Vesting Date (in	Intrinsic Value of Unit Awards on Vesting Date (in millions)

		millions)	
12/31/2013	572,353	$20.5	$36.2
12/31/2014	528,984	$22.4	$43.7
12/31/2015	506,393	$27.7	$34.4

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Cash Flow Effects of LTIP Settlements

We settle awards that vest by issuing limited partner units. The difference between the limited partner units issued to the participants and the total units accrued represents the minimum tax withholdings associated with the award settlement, which we pay in cash.

Settlement Date	Number of Limited Partner Units Issued, Net of Tax Withholdings	Minimum Tax Withholdings (in millions)	Employer Taxes (in millions)	Total Cash Taxes Paid (in millions)
January 2013	476,682	$12.3	$1.1	$13.4
January 2014	387,216	$14.8	$1.2	$16.0
January 2015	354,529	$17.8	$1.7	$19.5

Compensation Expense Summary

Equity-based incentive compensation expense for 2013, 2014 and 2015 was as follows (in thousands):

	Year Ended December 31, 2013			Year Ended December 31, 2014			Year Ended December 31, 2015		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2010 awards	$121	$73	$194	$—	$—	$—	$—	$—	$—
2011 awards	5,359	4,280	9,639	—	—	—	—	—	—
2012 awards	4,751	2,747	7,498	4,418	3,896	8,314	—	—	—
2013 awards	4,726	1,451	6,177	7,427	3,425	10,852	8,661	1,997	10,658
2014 awards	—	—	—	6,494	—	6,494	7,471	—	7,471
2015 awards	—	—	—	—	—	—	4,917	—	4,917
Time-based awards	575	—	575	1,624	—	1,624	1,199	—	1,199
Total	$15,532	$8,551	$24,083	$19,963	$7,321	$27,284	$22,248	$1,997	$24,245
Allocation of LTIP expense on our consolidated statements of income:									
G&A expense			$23,264			$26,700			$23,937
Operating expense			819			584			308
Total			$24,083			$27,284			$24,245

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 expenses that management does not consider when evaluating the core profitability of our separate operating segments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2013				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
	(in thousands)				
Transportation and terminals revenue(1)	$826,202	$203,459	$158,791	$—	$1,188,452
Product sales revenue	738,271	—	6,398	—	744,669
Affiliate management fee revenue	—	13,361	1,248	—	14,609
Total revenue	1,564,473	216,820	166,437	—	1,947,730
Operating expenses(1)	295,785	44,181	59,407	(3,179)	396,194
Cost of product sales	574,703	—	3,326	—	578,029
Earnings of non-controlled entities	—	(3,781)	(2,494)	—	(6,275)
Operating margin	693,985	176,420	106,198	3,179	979,782
Depreciation and amortization expense	86,926	24,119	28,006	3,179	142,230
G&A expenses	91,658	19,896	20,942	—	132,496
Operating profit	$515,401	$132,405	$57,250	$—	$705,056
Additions to long-lived assets	$361,134	$199,362	$32,563		$593,059

	As of December 31, 2013				
Segment assets	$2,811,398	$1,252,036	$648,061		$4,711,495
Corporate assets					91,812
Total assets					$4,803,307
Goodwill	$38,369	$12,082	$2,809		$53,260
Investments in non-controlled entities	$—	$345,904	$14,948		$360,852

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2014				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
	(in thousands)				
Transportation and terminals revenue[1]	$946,612	$341,915	$170,740	$—	$1,459,267
Product sales revenue	872,537	—	6,437	—	878,974
Affiliate management fee revenue	—	20,790	1,321	—	22,111
Total revenue	1,819,149	362,705	178,498	—	2,360,352
Operating expenses[1]	356,057	83,184	65,173	(3,513)	500,901
Cost of product sales	592,887	—	1,698	—	594,585
Earnings of non-controlled entities	—	(16,309)	(3,085)	—	(19,394)
Operating margin	870,205	295,830	114,712	3,513	1,284,260
Depreciation and amortization expense	101,642	27,800	28,786	3,513	161,741
G&A expenses	96,411	29,557	22,320	—	148,288
Operating profit	$672,152	$238,473	$63,606	$—	$974,231
Additions to long-lived assets	$163,753	$439,846	$18,413		$622,012
	As of December 31, 2014				
Segment assets	$2,875,412	$1,937,242	$647,900		$5,460,554
Corporate assets					40,855
Total assets					$5,501,409
Goodwill	$38,369	$12,082	$2,809		$53,260
Investments in non-controlled entities	$—	$599,757	$14,110		$613,867

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2015				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
	(in thousands)				
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	377,772	89,455	62,526	(3,851)	525,902
Cost of product sales	442,621	3,278	1,374	—	447,273
(Earnings) loss of non-controlled entities	193	(63,918)	(2,758)	—	(66,483)
Operating margin	777,021	381,365	119,524	3,851	1,281,761
Depreciation and amortization expense	96,244	35,681	31,036	3,851	166,812
G&A expenses	94,482	36,000	20,847	—	151,329
Operating profit	$586,295	$309,684	$67,641	$—	$963,620
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

(1) Includes adjustment of tender deductions as discussed in Note 2 – Summary of Significant Accounting Policies. The amounts adjusted for our refined products segment are $25.1 million and $24.8 million for 2013 and 2014, respectively. The amounts adjusted for our crude oil segment are $25.0 million and $31.8 million for 2013 and 2014, respectively.

17. Commitments and Contingencies

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $36.3 million and $31.4 million at December 31, 2014 and December 31, 2015, respectively. We have classified environmental liabilities as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be substantially paid over the next 9 years. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expenses were $(5.2) million, $5.0 million and $8.4 million for the years ended December 31, 2013, 2014 and 2015, respectively. The lower environmental expense for 2013 was primarily due to the $10.6 million favorable adjustment of an accrual for potential air emission fees.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2014 were $5.1 million, of which $1.3 million and $3.8 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, 2015 were $2.6 million, of which $0.7 million and $1.9 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets.

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Amounts received from insurance carriers and other third parties related to environmental matters during 2013, 2014 and 2015 were $4.2 million, $0.5 million and $0.5 million, respectively.

Other

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 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. Quarterly Financial Data (unaudited)

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

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue[(1)]	$633,892	$512,435	$535,832	$678,193
Total costs and expenses[(1)]	$359,269	$336,172	$311,640	$398,434
Operating margin	$347,535	$264,424	$299,268	$373,033
Net income	$242,554	$146,260	$198,620	$252,085
Basic net income per limited partner unit	$1.07	$0.64	$0.87	$1.11
Diluted net income per limited partner unit	$1.07	$0.64	$0.87	$1.10
2015				
Revenue[(1)]	$530,302	$498,427	$586,676	$573,048
Total costs and expenses[(1)]	$320,081	$315,206	$312,527	$343,502
Operating margin	$297,006	$286,145	$369,325	$329,285
Net income	$183,636	$177,391	$250,972	$207,123
Basic net income per limited partner unit	$0.81	$0.78	$1.10	$0.91
Diluted net income per limited partner unit	$0.81	$0.78	$1.10	$0.91

(1) Includes adjustment of tender deductions as discussed in Note 2 – Summary of Significant Accounting Policies. The amounts adjusted for 2014 are as follows: first quarter $15.3 million; second quarter $16.0 million; third quarter $14.2 million; and fourth quarter $11.1 million. The amounts adjusted for 2015 are as follows: first quarter $8.2 million; second quarter $10.9 million; and third quarter $9.4 million.

In the fourth quarter of 2014, total costs and expenses were increased $39.3 million by a lower-of-average-cost-or-market inventory adjustment, which resulted from a sharp decline in commodity prices during the quarter. Additionally, during the fourth quarter of 2014, the gains and losses we recognized from our NYMEX contracts, as a result of the lower commodity prices, had the impact of increasing product sales revenue by $111.6 million, increasing cost of product sales by $14.0 million and decreasing operating expense by $17.4 million, for a total increase to operating margin and net income of $115.0 million. During 2015, we recorded a lower-of-average-cost-or-market adjustment of $5.0 million combined related to our fractionation and crude oil inventories.

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19. Fair Value Disclosures

Fair Value Methods and Assumptions - Financial Assets and Liabilities

The following methods and assumptions were used in estimating fair value for our financial assets and liabilities:

- Energy commodity derivatives contracts. These include NYMEX futures agreements 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 include lease payments receivable under a direct-financing leasing arrangement and insurance receivables. Fair value was determined by estimating the present value of future cash flows using current market rates.

- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2014 and 2015; 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 recurring fair value measurements recorded or disclosed as of December 31, 2014 and 2015, based on the three levels established by ASC 820; Fair Value Measurements and Disclosures (in thousands):

			Fair Value Measurements as of December 31, 2014 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	$96,142	$96,142	$96,142	$—	$—
Interest rate contracts	$(26,478)	$(26,478)	$—	$(26,478)	$—
Long-term receivables	$28,611	$30,200	$—	$—	$30,200
Debt	$(2,967,019)	$(3,212,462)	$—	$(3,212,462)	$—

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			Fair Value Measurements as of December 31, 2015 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	$42,721	$42,721	$42,721	$—	$—
Interest rate contracts	$1,526	$1,526	$—	$1,526	$—
Long-term receivables	$20,374	$20,021	$—	$—	$20,021
Debt	$(3,439,622)	$(3,284,791)	$—	$(3,284,791)	$—

20. Distributions

Distributions we paid during 2013, 2014 and 2015 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution
2/14/2013	$0.5000	$113,340
5/15/2013	0.5075	115,040
8/14/2013	0.5325	120,707
11/14/2013	0.5575	126,374
Total	$2.0975	$475,461
2/14/2014	$0.5850	$132,835
5/15/2014	0.6125	139,079
8/14/2014	0.6400	145,324
11/14/2014	0.6675	151,568
Total	$2.5050	$568,806
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

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

21. Partners' Capital

The following table details the changes in the number of our limited partner units outstanding from January 1, 2013 through December 31, 2015:

Limited partner units outstanding on January 1, 2013	226,200,872
01/13—Settlement of 2010 award grants	476,682
During 2013—Other [(a)]	1,884
Limited partner units outstanding on December 31, 2013	226,679,438
02/14—Settlement of 2011 award grants	387,216
During 2014—Other [(a)]	1,603
Limited partner units outstanding on December 31, 2014	227,068,257
02/15—Settlement of 2012 award grants	354,529
During 2015—Other [(a)]	4,461
Limited partner units outstanding on December 31, 2015	227,427,247

(a) Limited partner units issued to settle the equity-based retainer paid to independent directors of our general partner.

Our partnership agreement allows us to issue additional partnership securities for any partnership purpose at any time and from time to time for consideration and on terms and conditions as our general partner determines, all without approval by the limited partners.

Limited partners holding our limited partner units have the following rights, among others:

- right to receive distributions of our available cash within 45 days after the end of each quarter;
- right to elect the board members of our general partner;
- right to remove Magellan GP, LLC as our general partner upon a 100% vote of outstanding unitholders;
- right to transfer limited partner unit ownership to substitute limited partners;
- right to receive an annual report, containing audited financial statements and a report on those financial statements by our independent public accountants, within 120 days after the close of the fiscal year end;
- right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year;
- right to vote according to the limited partners’ percentage interest in us at any meeting that may be called by our general partner; and
- right to inspect our books and records at the unitholders’ own expense.

In the event of liquidation, we would distribute all property and cash in excess of that required to discharge all liabilities to the partners in proportion to the positive balances in their respective capital accounts. The limited partners' liability is generally limited to their investment.

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22. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2015.

Non-recognizable events

On February 1, 2016, 218,046 phantom unit awards were issued pursuant to our long-term incentive plan. These grants included both performance-based and time-based phantom unit awards and have a three-year vesting period that will end on December 31, 2018.

On February 1, 2016, we issued 353,786 limited partner units, of which 350,552 were issued to settle unit award grants to certain employees that vested on December 31, 2015 and 3,234 were issued to settle the equity-based retainers paid to the directors of our general partner.

On February 12, 2016, we paid cash distributions of $0.785 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 5, 2016. The total distributions paid were $178.8 million.

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, 2015 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 are filed as part of this annual report.

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)	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).
*(e)	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).
Exhibit 4	
*(a)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).
*(b)	

	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004).
*(c)	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).
*(d)	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).
*(e)	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).
*(f)	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).
*(g)	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).

Exhibit No.	Description
*(h)	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).
*(i)	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).
*(j)	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).
*(k)	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).
*(l)	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).
Exhibit 10	
(a)	Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated January 26, 2016.
(b)	Description of Magellan 2016 Annual Incentive Program.
(c)	Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2016.
*(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).
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*(k)	Separation and Release of Claims Agreement dated as of May 18, 2015 between Magellan Midstream Holdings GP, LLC and Michael P. Osborne (filed as Exhibit 10.1 to Form 10-Q filed August 6, 2015).
*(l)	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.
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*(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.
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Exhibit 23	Consent of Independent Registered Public Accounting Firm.
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* 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 19, 2016

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 17, 2016
/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 19, 2016
/s/ WALTER R. ARNHEIM Walter R. Arnheim	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2016
/s/ ROBERT G. CROYLE Robert G. Croyle	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2016
/s/ PATRICK C. EILERS Patrick C. Eilers	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 16, 2016
/s/ STACY P. METHVIN Stacy P. Methvin	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2016
/s/ JAMES R. MONTAGUE James R. Montague	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 17, 2016
/s/ BARRY R. PEARL		February 16, 2016

Director of Magellan GP, LLC, General Partner of
Magellan Midstream Partners, L.P.

Barry R. Pearl

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