MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 22, 2013

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, 2012
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 (State or other jurisdiction of incorporation or organization)	73-1599053 (I.R.S. Employer Identification No.)
Magellan GP, LLC P.O. Box 22186, Tulsa, Oklahoma (Address of principal executive offices)	74121-2186 (Zip Code)

Registrant's telephone number, including area code: (918) 574-7000
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units representing limited partnership interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o
No x
Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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, 2012 was $7,970,585,707.
As of February 21, 2013, there were 226,679,438 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 2013 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
FORM 10-K
PART I
Item 1. Business
(a) General Development of Business

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.

Two-for-One Unit Split

In October 2012, we completed a two-for-one split of our limited partner units. Holders of record on September 28, 2012 received one additional limited partner unit at the close of business on October 12, 2012 for each unit owned on the record date. All unit and per unit amounts in this report have been retrospectively restated for this split.

BridgeTex Joint Venture
In November 2012, we formed BridgeTex Pipeline Company, LLC (“BridgeTex”), a joint venture with an affiliate of Occidental Petroleum Corporation. BridgeTex was formed to construct and operate the BridgeTex pipeline, a 400-mile pipeline capable of transporting 300,000 barrels per day of Permian Basin crude oil from Colorado City, Texas for delivery to our East Houston, Texas terminal; a 50-mile pipeline between East Houston and Texas City, Texas; and approximately 2.6 million barrels of crude oil storage. We expect to spend approximately $600 million in connection with our 50% ownership interest in BridgeTex. We are serving as construction manager and will serve as operator of BridgeTex upon its completion, which is expected in mid-2014.
(b) Financial Information About Segments
See Part II—Item 8. Financial Statements and Supplementary Data.

(c) Narrative Description of Business

We are principally engaged in the transportation, storage and distribution of petroleum products. As of December 31, 2012, our asset portfolio consisted of:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 49 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six terminals.

Petroleum products transported, stored and distributed through our petroleum pipeline system and petroleum terminals include:

- refined petroleum products, which are the output from refineries and are primarily used as fuels by consumers. Refined petroleum 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, which are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

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

- heavy oils and feedstocks, which 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, which are used as feedstocks by refineries; and

- biofuels, such as ethanol and biodiesel, which are increasingly required by government mandates.

Refined Petroleum Products Logistics Industry Background

The U.S. petroleum products transportation and distribution system links oil refineries to end-users of gasoline and other petroleum products. This system is comprised of a network of pipelines, terminals, storage facilities, tankers, barges, railcars and trucks. For transportation of petroleum products, pipelines are generally the lowest-cost alternative for intermediate and long-haul movements between different markets. Throughout the distribution system, terminals play a key role in moving products to the end-user markets by providing storage, distribution, blending and other ancillary services.

The Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. According to the “Annual Refinery Report for 2012” published by the Energy Information Administration (“EIA”), the Gulf Coast region accounted for approximately 46% of total U.S. daily refining capacity. The role of Gulf Coast refiners has become even more significant given the recent shutdown of refining capacity in the Northeast U.S.

Crude Oil Logistics Industry Background

The crude oil available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties. This is due to crude oil produced from different producing regions, whether from within or outside the U.S., that may have unique qualities, each with varying economic attributes. Consequently, different refineries have developed a distinct configuration of process units designed to handle particular grades of crude oil. This creates transportation, terminalling and storage challenges associated with regional volumetric supply and demand imbalances. In many cases, these factors result in the need for certain grades to be batched or segregated in the transportation and storage processes or blended to precise specifications. One of the largest storage hubs for crude oil is in Cushing, Oklahoma, the delivery point for crude oil futures contracts traded on the New York Mercantile Exchange ("NYMEX"). From Cushing, the crude oil is shipped to various refineries throughout the U.S. With higher crude prices and improved drilling technology, new domestic fields are being developed and previously existing fields are being redeveloped, increasing the need for new or expanded transportation and storage infrastructure.

Description of Our Businesses

PETROLEUM PIPELINE SYSTEM

Our common carrier petroleum pipeline system extends approximately 9,600 miles and covers a 14-state area, extending from the Gulf Coast refining region across Texas and through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Our pipeline system transports petroleum products and includes 49 terminals. The products transported on our pipeline system are largely transportation fuels and in 2012 were comprised of 48% gasoline, 30% distillates, 16% crude oil and 6% aviation fuel and LPGs. Refined product and LPG shipments originate on our pipeline system from direct connections to refineries, at or near our terminals and through interconnections with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end-users. Crude oil shipments originate on our pipeline system from connections to crude oil terminals and through interconnections with other pipelines for transportation and distribution to refineries or terminals.

Our petroleum pipeline system segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,		
	2010	2011	2012
Percent of consolidated revenues	85%	84%	82%
Percent of consolidated operating margin	79%	77%	75%
Percent of consolidated total assets	71%	67%	65%

See Note 15—Segment Disclosures in the accompanying consolidated financial statements for additional financial information about our petroleum pipeline system segment.

The portion of our petroleum pipeline system that ships refined products and LPGs is dependent on the ability of refiners and marketers to meet the demand for those products in the markets they serve through their shipments on our pipeline system. According to January 2013 projections provided by the EIA, the demand for refined petroleum products in the primary market areas served by our petroleum pipeline system, known as West North Central and West South Central census districts, is expected to remain relatively stable over the next 10 years. The total production of refined petroleum products from refineries located in the West North Central district has historically been insufficient to meet the demand for refined petroleum products in that region. Any excess West North Central demand has been and is expected to be met largely by refined petroleum products shipped via pipelines from Gulf Coast refineries that are located in the West South Central census district.

Our petroleum pipeline system is well-connected to Gulf Coast refineries. In addition to our own pipeline that originates in the Gulf Coast region, we also have interconnections with third-party pipelines that originate in the Gulf Coast region. These connections to Gulf Coast refineries, together with our pipeline's extensive network throughout the West North Central district, should aid us in accommodating any demand growth or supply shifts that may occur.

The maximum number of barrels our petroleum pipeline system can transport per day depends upon the operating balance achieved at a given time between various segments of our pipeline system. This balance is dependent upon the mix of petroleum products to be shipped and the demand levels at the various delivery points. We believe that we will be able to accommodate demand increases in the markets we serve through expansions or modifications of our petroleum pipeline system, if necessary.

The portion of our petroleum pipeline system that ships crude oil is dependent in part on the production levels and related crude oil demand by Houston-area refineries. Additional connections for this pipeline system are being developed that will provide access to a broader group of origins and refineries in the Houston refining region.

The conversion and reversal of our Crane-to-Houston pipeline, also known as Longhorn pipeline, is an example of modifications we are making to our pipeline system in response to market demand. This project converts a portion of our refined petroleum products system into crude oil service and will reverse the flow bringing Permian Basin crude oil from Crane, Texas to our Houston-area crude oil distribution system. The 225,000 barrel per day capacity of the line was fully subscribed during our 2012 open season and is expected to be operational in early 2013 with full capacity reached in the second half of the year.

We shifted the volumes of refined products we previously transported on the Houston-to-El Paso pipeline section to a nearby pipeline section which we own; therefore, we do not expect a loss of revenues or operating margin from these movements as a result of the reversal.

The operating statistics below reflect our petroleum pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2010	2011	2012
Shipments (thousand barrels):			
Refined products:			
Gasoline	194,338	208,852	223,692
Distillates	122,929	136,003	136,709
Aviation fuel	22,612	25,245	21,557
LPGs	4,949	4,927	8,475
Crude oil	14,658	43,239	71,993
Total shipments	359,486	418,266	462,426
Capacity leases	27,084	30,672	15,024
Total shipments, including capacity leases	386,570	448,938	477,450
Daily average (thousand barrels)	1,059	1,230	1,305

The increase in total shipments for 2011 was primarily due to acquisitions and growth projects. The increase in total shipments for 2012 was primarily due to an increase in the utilization of our Houston-area crude oil distribution system.

Operations. Our petroleum pipeline system is the longest common carrier pipeline for refined petroleum products and LPGs in the U.S. Through direct refinery connections and interconnections with other interstate pipelines, our system can access approximately 44% of U.S. refining capacity. Substantially all of the shipments on our pipeline system are for third parties, and we do not take title to those products. We do take title to products related to our petroleum products blending and fractionation activities, and until we converted a portion of our Houston-to-El Paso pipeline segment in 2012, we took title to the linefill related to this pipeline section and a portion of the petroleum products we transported on this pipeline for sale in El Paso, Texas. Furthermore, under our tariffs, we are allowed to deduct from our shipper's inventory a prescribed quantity of the products our shippers transport on our pipeline to compensate us for metering inaccuracies, evaporation or other events that result in volume losses during the shipment process. To the extent we can manage our volume loss below the deducted amount, we take title to those products, which we can sell and thereby reduce our operating expenses.

In 2012, our petroleum pipeline system generated 73% of its revenues (excluding product sales revenues) from transportation tariffs on volumes shipped. These transportation tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All interstate transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission (“FERC”). Included as part of these tariffs are charges for terminalling and storage of products at 33 of our pipeline system's 49 terminals. Revenues from terminalling and storage at our other 16 terminals are at privately-negotiated rates.

In 2012, our petroleum pipeline system generated the remaining 27% of its revenues (excluding product sales revenues) from leasing pipeline and storage tank capacity to shippers and from providing services such as ethanol and biodiesel unloading and loading, additive injection, custom blending, terminalling, laboratory testing and data services to shippers, which are performed under a mix of “as needed,” monthly and long-term agreements. We receive a fee for operating a 135-mile pipeline (in which we own a 50% interest) that transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to National Cooperative Refining Association's refinery in McPherson, Kansas and HollyFrontier's refinery in El Dorado, Kansas. Beginning in December 2012, we receive a fee for managing the construction of approximately 450 miles of pipeline and 2.6 million barrels of storage (in which we will own a 50% interest) which, when complete, will transport crude oil from Colorado City, Texas to the Houston Gulf Coast area.

Product sales revenues for the petroleum pipeline system primarily result from our petroleum products blending and transmix fractionation activities. Our petroleum products blending activity involves purchasing LPGs and blending them into gasoline, which creates additional gasoline available for us to sell. This activity is limited by seasonal gasoline vapor pressure specification requirements and by the varying quality of the product delivered to us at our pipeline origins. We typically lock in most of the margin from this blending activity by entering into either forward physical or NYMEX gasoline futures contracts at the time we purchase the related LPGs. These blending activities accounted for approximately 90% of the total product margin for the petroleum pipeline system during 2012. If the differential between the cost of LPGs (butane) and the price of gasoline were to narrow, which generally occurs when crude prices decrease, the product margin we earn from these activities would be negatively impacted. We also operate two fractionators along our pipeline system that separate transmix, which is an unusable mixture of various petroleum products, into its original components. We purchase transmix from third parties and sell the resulting separated petroleum products. Prior to beginning the conversion of a portion of our system from refined product service to crude service in 2012, we also purchased petroleum products for shipment on the Houston-to-El Paso pipeline section to facilitate product shipments on the pipeline, and we sold those products in the El Paso, Texas wholesale market. Product margin from all of these activities was $81.3 million, $126.8 million and $122.0 million for the years ended December 31, 2010, 2011 and 2012, 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 revenues less product purchases, is used by management to evaluate the profitability of our commodity-related activities. A reconciliation of the components of product margin to operating profit, the nearest GAAP measurement, is provided in Note 15—Segment Disclosures to the consolidated financial statements included in this Annual Report on Form 10-K.

Commodity Risk Management. 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 as these activities could expose us to significant losses. Our blending and fractionation activities require us to carry significant levels of inventories. We use derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale obligations. 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. Our strategies are primarily intended to mitigate and manage price risks that are inherent in our blending and fractionation activities.

Facilities. Our petroleum pipeline system consists of an approximate 9,600-mile pipeline and 49 terminals and includes approximately 40 million barrels of aggregate usable storage capacity. The terminals on our pipeline system deliver petroleum products primarily into tank trucks.

Petroleum Products Supply. Petroleum products originate from refineries, pipeline interconnection points and terminals along our pipeline system. In 2012, approximately 57% of the petroleum products transported on our petroleum pipeline system originated from 13 direct refinery connections and 43% originated from connections with other pipelines or terminals.

The portion of our system that transports refined petroleum products and LPGs is directly connected to and receives product from the 13 refineries shown below:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
Calumet Specialty Products	Superior, WI
CVR Energy	Coffeyville, KS
CVR Energy	Wynnewood, OK
Flint Hills Resources	Pine Bend, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
Marathon	Texas City, TX
National Cooperative Refining Association	McPherson, KS
Phillips 66	Ponca City, OK
St. Paul Park Refining	St. Paul, MN
Valero	Ardmore, OK
Valero	Houston, TX
Valero	Texas City, 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
Refined Products:		
BP	Manhattan, IL	Whiting, IN refinery
CHS	Fargo, ND	Laurel, MT refinery
Explorer	Glenpool, OK; Mt. Vernon, MO; Dallas, TX; East Houston, TX; Greenville, TX	Various Gulf Coast refineries
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	Borger, TX refinery
Shell	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries
Crude:		
Genoa Junction	Houston, TX	

		Two pipelines near the Houston ship channel
Speed Junction	Houston, TX	Various Houston, TX terminals and two pipelines along the Houston ship channel

Customers and Contracts. We ship petroleum products for several different types of customers, including independent and integrated oil companies, wholesalers, retailers, railroads, airlines and regional farm cooperatives. End markets for refined product 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. Crude shippers are predominately refiners that ship crude oil for their own refinery needs. 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 and/or term commitments in exchange for reduced tariff rates or capital expansion commitments on our part. For 2012, approximately 45% 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, 2012, 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 petroleum pipeline system.

For the year ended December 31, 2012, our petroleum pipeline system had approximately 60 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies and farm cooperatives. Revenues attributable to these top 10 shippers for the year ended December 31, 2012 represented 46% of total revenues for our petroleum pipeline system and 63% of revenues excluding product sales.

Our product sales have historically been primarily to trading and marketing companies. These sales agreements are generally short-term in nature.

Markets and Competition. In certain markets, barge, truck or rail provide an alternative source for transporting petroleum products; however, pipelines are generally the lowest-cost alternative for petroleum product 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 line to use.

Another form of competition for all 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 have been able to compete with these alternatives through price incentives and through long-term commercial arrangements with potential exchange partners. Nevertheless, a significant amount of exchange activity has occurred historically and is likely to continue.

Government mandates increasingly require the use of renewable fuels, particularly ethanol. Due to concerns regarding corrosion and product contamination, pipelines have generally not shipped ethanol, and most ethanol is transported by railroad or truck. The increased use of ethanol has and will continue to compete with shipments on our pipeline system. However, most terminals on our pipeline system have the necessary infrastructure to blend ethanol with refined products. We earn revenues for these services that to date have been more than sufficient to offset any reduction in transportation revenues due to ethanol blending.

PETROLEUM TERMINALS

We operate two types of terminals: storage terminals and inland terminals. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we can charge for our services. In general, we do not take title to the products that are stored in or distributed from our terminals. Our petroleum terminals segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,		
	2010	2011	2012

Percent of consolidated revenues	14%	15%	16%
Percent of consolidated operating margin	22%	22%	23%
Percent of consolidated total assets	27%	26%	26%

See Note 15—Segment Disclosures in the accompanying consolidated financial statements for additional financial information about our petroleum terminals segment.

Storage Terminals

We own and operate six storage terminals located along coastal waterways in New Haven, Connecticut, Wilmington, Delaware, Gibson and Marrero, Louisiana and Corpus Christi and Galena Park, Texas, and a crude oil storage terminal in Cushing, Oklahoma. Our storage terminals have an aggregate usable storage capacity of approximately 36 million barrels and provide distribution, storage, blending, inventory management and additive injection services for refiners and other large end-users of petroleum products.

Our Cushing terminal primarily receives and distributes crude oil via common carrier pipelines and short-haul pipeline connections with neighboring crude oil terminals. Our other storage terminals primarily receive petroleum products by ship and barge, short-haul pipeline connections from neighboring refineries and common carrier pipelines. We distribute petroleum products from these storage terminals by all of those means as well as by truck and rail. Products that we store include refined petroleum products, blendstocks, crude oil, condensate, heavy oils and feedstocks. In addition to providing storage and distribution services, our storage terminals provide ancillary services including heating, blending and mixing of stored products and additive injection services.

Our storage terminals generate revenues primarily through providing long-term storage services for a variety of customers. Refiners and chemical companies typically use our storage terminals because their facilities are inadequate, either because of size constraints 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.

We own a 50% interest in Texas Frontera, LLC which owns 0.8 million barrels of storage at our Galena Park, Texas terminal. This storage is leased to an affiliate of the party that owns the remaining 50% interest. We receive a fee for operating the storage tanks in addition to our portion of the net earnings of the joint venture, which is recognized as equity earnings.

Customers and Contracts. We have long-standing relationships with oil refiners, suppliers and traders at our facilities. During 2012, approximately 96% of our storage terminal capacity was utilized. As of December 31, 2012, approximately 90% of our usable storage capacity was under contracts with remaining terms in excess of one year or that renew on an annual basis. Approximately 20% of the usable storage capacity under these contracts is subject to automatic annual renewal unless otherwise terminated, the majority of which relates to one contract. The average remaining life of our storage contracts was approximately three years as of December 31, 2012. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

Markets and Competition. We believe that the continued strong demand for our storage terminals results from our cost-effective distribution services and key transportation links, which provide us with a stable base of storage fee revenues. The heating and blending services we provide at our storage terminals attract additional demand for our storage services and result in increased revenue opportunities. Demand can also be influenced by projected changes in and volatility of petroleum product prices.

Several major and integrated oil companies have their own proprietary storage terminals that are or have been used in their refining operations. If these companies choose to shut down their refining operations and elect to store and distribute petroleum products through their proprietary terminals, we could experience increased competition for the services we provide. This trend is especially evident in the Northeastern U.S., where several refineries have been or are in the process of being idled. In addition, other companies have facilities that offer competing storage and distribution services, and a significant amount of additional competing storage capacity has been constructed recently.

Inland Terminals

We own and operate a network of 27 refined petroleum products terminals located primarily in the Southeastern U.S. Our terminals have a combined capacity of more than 5 million barrels. Our customers utilize these facilities to take delivery of refined petroleum products transported on major common carrier interstate pipelines. The majority of our inland terminals connect to the Colonial or Plantation pipelines, and some facilities have multiple pipeline connections. We load and unload products through an automated system that allows products to move from the common carrier pipelines to our storage tanks and from our storage tanks to a truck or railcar loading rack. During 2012, gasoline represented approximately 65% of the product volume distributed through our inland terminals, with the remaining 35% consisting of distillates.

We operate our inland terminals as independent distribution terminals, primarily serving the retail, industrial and commercial sales markets. We provide inventory and supply management, distribution and other services such as injection of gasoline additives at our inland terminals. In addition, most of our inland terminals have ethanol blending capabilities.

We generate revenues by charging our customers a fee based on the amount of product we deliver through our inland terminals. We charge these fees when we deliver the product to our customers and load it into a truck or railcar. In addition to throughput fees, we generate revenues by charging our customers a fee for injecting additives or blending ethanol into their petroleum products. We also generate product margins from the sale of terminal product gains.

Customers and Contracts. We enter into a variety of contracts with customers that vary in term and commitment. A number of these agreements contain a minimum throughput provision that obligates the customer to move a minimum amount of product through our terminals or pay for terminal capacity reserved but not used. These contracts automatically renew at the end of the contract term unless we or our customer provide written notice to cancel the agreement. Our customers include retailers, wholesalers, exchange transaction customers and traders.

Markets and Competition. We 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 competition primarily comes from distribution companies with marketing and trading arms, other independent terminal operators and refining and marketing companies.

AMMONIA PIPELINE SYSTEM

We own an 1,100-mile common carrier ammonia pipeline system. Our pipeline system transports ammonia from production facilities in Texas and Oklahoma to terminals in the Midwest. The ammonia we transport is primarily used as a nitrogen fertilizer. The ammonia pipeline system segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,		
	2010	2011	2012
Percent of consolidated revenues	1%	1%	2%
Percent of consolidated operating margin	(1)%	1%	2%
Percent of consolidated total assets	1%	1%	1%

See Note 15–Segment Disclosures in the accompanying consolidated financial statements for additional financial information about our ammonia pipeline system segment.

Operations. We generate our ammonia pipeline system revenues through transportation tariffs and by charging our customers for services at the six terminals we own. We do not produce or trade ammonia, and we do not take title to the ammonia we transport.

Facilities. Our ammonia pipeline system originates at production facilities in Borger, Texas and Enid and Verdigris, Oklahoma and terminates in Mankato, Minnesota. We transport ammonia to 13 delivery points along our ammonia pipeline system, including six terminals that we own. The facilities at these points provide our customers with the ability to deliver ammonia to distributors who sell the ammonia to farmers, store ammonia for future use and remove ammonia from our pipeline for further distribution.

Customers and Contracts. We ship ammonia for three customers. Each of these customers has an ammonia production facility as well as related storage and distribution facilities connected to our ammonia pipeline. We have rolling three-year transportation agreements with our three customers. Each transportation agreement contains a ship-or-pay provision whereby each customer committed a tonnage that it expects to ship. If a customer fails to ship its annual commitment, that customer must pay for the unused pipeline capacity. Aggregate annual commitments from our customers for the period July 1, 2012 through June 30, 2013 are 575,000 tons, although our customers have typically shipped more than their annual commitments.

Markets and Competition. Demand for nitrogen fertilizer typically follows a combination of weather patterns, growth in population, acres planted and fertilizer application rates. Because natural gas is the primary feedstock for the production of ammonia, the profitability of our customers is impacted by natural gas prices. To the extent our customers are unable to pass on higher costs to their customers, they may reduce shipments through our ammonia pipeline system during periods of high natural gas prices.

We compete primarily with ammonia shipped by rail carriers. Because the transportation and storage of ammonia requires specialized handling, we believe that pipeline transportation is the safest and most cost-effective method for transporting bulk quantities of ammonia. We also compete to a limited extent in the areas served by the far northern segment of our ammonia pipeline system with an ammonia pipeline owned by NuStar Energy, which originates on the Gulf Coast and transports domestically produced and imported ammonia.

OPERATING SEGMENT CHANGES

We have undertaken a number of strategic changes in our businesses, particularly in the area of our crude activities, which have had or will have a significant impact on the way we manage our operations. Because of these changes, and in order to achieve certain other operational efficiencies, we have modified our organizational structure. Accordingly, effective January 1, 2013, we redesigned our internal management reports to correspond to this new organizational structure, resulting in changes to our reporting segments. Our new reporting segments will be as follows:

- Refined products pipeline and terminals segment,
- Crude pipeline and terminals segment, and
- Marine storage segment.

The primary changes from our current reporting segments to our new reporting segments include:

- The refined products pipeline and terminals segment will include the financial results from most of our petroleum pipeline system segment as well as results from the inland terminals and the ammonia pipeline system segment. The inland terminals are currently reported with the financial results of the petroleum terminals segment. The financial results of our Cushing, Oklahoma and South Texas crude pipelines, the crude components of our East Houston, Texas terminal, and the Osage Pipe Line Company, LLC ("Osage"), which are currently included with the petroleum pipeline system segment, will be included with the financial results of the crude pipeline and terminals segment.

- The crude pipeline and terminals segment will include the financial results for: (i) the Crane-to-Houston crude pipeline; (ii) the Cushing, Oklahoma pipeline and terminal; (iii) the South Texas crude pipeline; (iv) the crude components of our East Houston, Texas terminal; (v) the condensate components of our Corpus Christi, Texas terminal; (vi) the Gibson, Louisiana terminal; and (vii) the equity earnings of the Osage pipeline, the Double Eagle pipeline, and the BridgeTex pipeline. The Crane-to-Houston reversal project is expected to be operational in early 2013 with full capacity reached in the second half of the year. The Double Eagle pipeline, in which we hold a 50% joint ownership interest, will transport condensate from the Eagle Ford shale in West Texas to our terminal in Corpus Christi, Texas, and is expected to be fully operational by the second half of 2013. The BridgeTex pipeline system, in which we hold a 50% ownership interest, will transport crude oil from West Texas for delivery to refineries along the Houston, Texas ship channel. The BridgeTex pipeline is currently under construction and is expected to be operational in mid-2014.

- The marine storage segment will include the financial results from our petroleum terminals segment except that the financial results from our inland terminals will be reported with the financial results of the refined products pipeline and terminals segment. Additionally, the Cushing, Oklahoma and Gibson, Louisiana terminals and the crude components of our Corpus Christi, Texas terminal will be reported with the financial results of the crude pipeline and terminals segment.

GENERAL BUSINESS INFORMATION

Major Customers

The percentage of revenue derived by customers that accounted for 10% or more of consolidated total revenues is provided in the table below. No other customer accounted for more than 10% of our consolidated total revenues for 2010, 2011 or 2012. The majority of the revenues from Customers A and B resulted from sales to those customers of refined petroleum products that were generated in connection with our petroleum products blending and fractionation activities, and from sales associated with the management of our linefill for the Houston-to-El Paso pipeline section, all of which are or were activities conducted by our petroleum pipeline system segment. In general, accounts receivable from these customers are due within three days of sale. We believe that, in the event Customer A and B were unable or unwilling to do so, other companies would purchase from us the petroleum products we have for sale.

	Year Ended December 31,		
	2010	2011	2012
Customer A	11%	21%	14%
Customer B	13%	8%	7%
Total	24%	29%	21%

Tariff Regulation

Interstate Regulation. Our petroleum 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 oil 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. Rates of interstate oil pipeline companies, including approximately one-third of the shipments on our petroleum pipeline system, are currently regulated by the FERC primarily through an index methodology, which for the five-year period beginning July 1, 2011, was set at the annual change in the producer price index for finished goods (“PPI-FG”) plus 2.65%. In general, we are permitted to raise our rates up to the ceiling established by the PPI-FG index plus 2.65%, but rate increases 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/or pay reparations for up to two years of over-earning. In addition to rate indexing, interstate oil pipeline companies may elect to support rate filings by obtaining authority to charge market-based rates, by settlement with respect to existing rates or through an agreement with an unaffiliated person who intends to use the related service. Approximately two-thirds of our petroleum pipeline system's markets are deemed competitive by the FERC, and we are allowed to charge market-based rates in these markets.

The Surface Transportation Board (“STB”), 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. If the STB finds that a carrier's rates violate these statutory commands, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives. The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline entity holds market power, then the pipeline entity may be required to show that its rates are reasonable. The STB has not initiated investigations of the rates or practices of our ammonia pipeline since our formation in 2000.

Intrastate Regulation. Some shipments on our petroleum pipeline system move within a single state and thus are considered to be intrastate commerce. Our petroleum pipeline system is subject to certain regulations with respect to such intrastate transportation by state regulatory authorities in the states of Colorado, Illinois, Kansas, Minnesota, Oklahoma and Texas. However, in most instances, the state commissions have not initiated investigations of the rates or practices of petroleum pipelines.

Because in some instances we transport ammonia between two terminals in the same state, our ammonia pipeline operations are subject to regulation by the state regulatory authorities in Iowa, Nebraska, Oklahoma and Texas. Although the Oklahoma Corporation Commission and the Texas Railroad Commission have the authority to regulate our rates, the state commissions have generally not investigated the rates or practices of ammonia pipelines in the absence of shipper complaints.

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 petroleum 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. FERC may also order reparations and suspend tariffs, including our authority to charge negotiated rates, for violations of the Interstate Commerce Act in connection with interstate oil pipeline transportation.

Under the Commodity Exchange Act, the Commodity Futures Trading Commission ("CFTC") is directed to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to assess fines of up to $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.
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 operated and maintained in material compliance with these laws and regulations and in accordance with other generally accepted industry standards and practices.

Environmental. 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. Remediation costs are estimates and total remediation costs may exceed 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 $49.6 million and $48.3 million at December 31, 2011 and 2012, 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 10 years.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $7.7 million and $7.9 million at December 31, 2011 and 2012, 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. We have pollution legal liability insurance policies to cover pre-existing unknown conditions for a portion of our assets that have various terms, with most expiring between 2014 and 2017.

Clean Air Act. Our operations are subject to the federal Clean Air Act, as amended ("CAA"), and comparable state and local laws. The CAA requires sources of emissions to obtain construction permits or approvals for new construction and operating permits for existing operations. We believe that we currently hold or have applied for all necessary air permits.

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas that did not meet the attainment deadline. The CAA 185 fees are required annually until the area is redesignated as an attainment area for ozone. The Environmental Protection

Agency ("EPA") is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality (“TCEQ”) is currently considering a “Failure to Attain Rule” to implement the requirements of CAA 185. The draft Failure to Attain Rule is anticipated to be adopted in 2013 and is expected to provide for the collection of an annual failure to attain fee for excess emissions. We have certain facilities in the Houston area that will be subject to the TCEQ's Failure to Attain Rule.

Management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston area facilities and our estimate of the possible range of loss associated with this matter is from zero to $14.3 million. As of December 31, 2012, we have accrued $10.9 million as a long-term environmental liability related to this matter. Management believes that recent indications with regard to this matter by the TCEQ and the EPA have been favorable to us. The final

Failure to Attain Rule is expected to be published in 2013; therefore, it is likely that our estimate of this loss will change in the near term.

Stationary Engine Emission Standards. The EPA has set a May 2013 compliance date for the reduction of carbon monoxide from the exhausts of large stationary reciprocating internal combustion engines. Some of the engines on our petroleum pipeline system are subject to these EPA mandates. The EPA rule, which became effective in May 2010, generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance, which is the solution we are pursuing; however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. We have received a one-year extension to meet the stationary engine emission standards. If we are not able to modify or replace these engines by May 2014, sections of our petroleum pipeline system could experience capacity reductions or we could be assessed significant penalties until the required emission reductions are achieved.

Department of Homeland Security Appropriation Act of 2007. This act requires the Department of Homeland Security (“DHS”) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS has issued rules that establish chemicals of interest and their respective threshold quantities that trigger compliance with these standards. The owners of facilities covered by these DHS rules that are determined by the DHS to pose a higher level of security risk are required to prepare and submit security vulnerability assessments and site security plans as well as comply with other regulatory requirements, including those regarding inspections, audits, record-keeping and protection of chemical-terrorism vulnerability information.

The DHS has preliminarily determined that one of our facilities storing butane meets their security risk screening threshold and is regulated under the DHS Chemical Facility Anti-Terrorism Standards ("CFATS"). We have submitted a security plan for this facility and are awaiting a response from the DHS as to whether additional security measures will be needed for this facility to be in compliance with CFATS. The DHS has continued to delay final security risk determinations for gasoline storage facilities while it addresses program implementation challenges. Management believes that our costs to comply with CFATS will not be material to our operating results, financial position or cash flows.

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 because 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 petroleum products. The Oil Pollution Act amended provisions of the Federal Water Pollution Control Act of 1972, as amended ("Water Pollution Control Act"), and other statutes as they pertain to prevention and response to crude oil and refined product spills. The Oil Pollution Act subjects owners of facilities to strict, joint and potentially significant liability for removal costs and certain other consequences of an oil spill such as natural resource damages, where the product spills into navigable waters, along federal shorelines or in the exclusive economic zone of the U.S. In the event of an oil spill from one of our facilities into navigable waters, substantial liabilities could be imposed. States in which we operate have also enacted similar laws. The Water Pollution Control Act imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. This law and comparable state laws require that permits be obtained to discharge pollutants into state and federal waters and impose substantial potential liability for non-compliance. Where required, we hold discharge permits that were issued under the Water Pollution Control Act or a state-delegated program. While we have occasionally exceeded permit discharges at some of our terminals, we do not expect our non-compliance with existing permits to have a material adverse effect on our results of operations, financial position or cash flows.

Greenhouse Gas Emissions. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Among several such regulations, in May 2010, the EPA finalized its "tailoring rule," determining which stationary sources of greenhouse gases are required to obtain permits and implement best available control technology standards on account of their greenhouse gas emission levels.

Further, Congress has considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction. Such legislation would have established an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. The current administration supports legislation to reduce greenhouse gas emissions through an emission allowance system. As allowances under such a system would be expected to significantly escalate in cost over time, the net effect of any potential cap-and-trade legislation would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, if it occurs, may result in materially increased compliance and operating costs. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Maintenance. Our pipeline systems are subject to regulation by the U.S. Department of Transportation 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 petroleum, petroleum 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.

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.

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. We believe we are in material compliance with OSHA and comparable state safety regulations.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 reauthorized funding for federal pipeline safety programs through 2015, 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. The Pipeline Hazardous Materials Safety Administration of the U.S. Department of Transportation has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Compliance with such legislative and regulatory changes could have a material 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 for the transfer of the assets necessary for us to operate our business in all material respects.

We believe that we have satisfactory title to all of our assets or are entitled to indemnification from former affiliates for title defects to our ammonia pipeline and certain marine terminal assets that arise before February 2016. 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, 2012, we had 1,339 employees. At December 31, 2012, the labor force of 545 employees assigned to our petroleum pipeline system was concentrated in the central U.S. Approximately 41% of these employees were represented by the United Steel Workers and covered by a collective bargaining agreement that expires January 31, 2015. The labor force of 305 employees assigned to our petroleum terminals operations at

December 31, 2012 was primarily located in the Southeastern and Gulf Coast regions of the U.S. Approximately 9% of these employees were represented by the International Union of Operating Engineers and covered by a collective bargaining agreement that expires October 31, 2013. At December 31, 2012, the labor force of 20 employees assigned to our ammonia pipeline system was concentrated in the central U.S. None of these employees were covered by a collective bargaining agreement.

(d) Financial Information About Geographical Areas

We have no international activities. For all periods included in this report, all our revenues were derived from operations conducted in, and all of our assets were located in, the U.S. See Note 15–Segment Disclosures in the notes to consolidated financial statements for information regarding our revenues 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. In that case, the market price of our limited partner units could decline.

Risks Related to Our Business

We may not be able to generate sufficient cash from operations to allow us to pay quarterly distributions at current levels following establishment of cash reserves and payment of fees and expenses.

The amount of cash we can distribute on our limited partner units principally depends upon the cash we generate from our operations, as well as cash reserves established by our general partner and working capital borrowings. 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 fluctuates from quarter to quarter and may change over time. Significant and sustained reductions in the cash generated by our operations could reduce our ability to pay quarterly distributions at the current level in future periods.

Our financial results depend on the demand for the petroleum products that we transport, store and distribute, among other factors, and unfavorable economic conditions 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, including the challenges that have affected economic conditions in the U.S. over the last several years. 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 in the market prices of petroleum products, which may reduce 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;
- 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, in August 2012 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. The proposed standards are intended to reduce demand for petroleum products, and if implemented these and any similar standards 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 transportation fuel. Increases in the use of such alternative transportation fuels could have a material impact on the volume of petroleum-based fuels transported on our pipeline or distributed through our terminals.

A decrease in lease renewals or renewals at substantially lower rates at our storage terminals or in leased storage along our petroleum pipeline system could cause our leased storage revenues to decline, which would adversely impact our results of operations and the amount of cash we generate.

Most of the revenues we earn from leased storage at our storage terminals and along our pipeline system are 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 revenues 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 financing, which could adversely affect our results of operations, financial position and cash flows.

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 and/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 would 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 revenues from our petroleum products blending and fractionation activities, as well as from the sale of product generated by the operation of our pipelines and terminals. We also maintain product inventory related to these activities. Significant fluctuations in market prices of petroleum products could result in 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 non-cash 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 profits and could result in material cash obligations that could negatively impact our financial position or our ability to pay distributions to our unitholders.

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 815-30, 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 different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

We are exposed to counterparty credit risk. Nonpayment and nonperformance by our customers, vendors, lenders or derivative counterparties could materially reduce our revenues, impair our liquidity, increase our expenses 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 rely to realize the expected return on those expenditures, and nonperformance by our customers on those commitments could result in substantial losses to us. Similarly, nonperformance by vendors who have committed to provide products or services to us could result in higher costs, reduce our revenues or otherwise interfere with the conduct of our business. 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 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 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.

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/or reduce our cash flows and ability to pay distributions.

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 $700 million for organic growth projects during 2013. 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 will rely on new capital to refinance these obligations. For example, $250 million of our long-term notes mature in 2014, and another $250 million mature in 2016, and we anticipate raising new capital to refinance these obligations on or prior to their maturity.

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 and/or our cash flows, and could result in the dilution of the interests of our existing unitholders.

Economic conditions that have persisted during the last several years amplify certain risks inherent in our business.

The U.S. and many other countries have experienced weak economic conditions and frequently volatile financial markets since 2007. During that period, these conditions have periodically resulted in significant reductions in access to capital. Additionally, capital constraints coupled with significant energy price volatility and generally weak economic conditions have resulted in financial and liquidity issues for many companies, including some of our customers, as well as national, state and municipal governments. Such conditions have created significant uncertainty in the economic outlook and have amplified the potential impact and likelihood of the occurrence of certain risks inherent in our business. Such risks, each of which could have a material adverse impact on us, include:

- increased cost of capital and increased difficulties accessing capital to fund expansion and acquisition activities;
- the inability or unwillingness of lenders to honor their contractual commitments;
- the failure of customers to timely or fully pay amounts due to us;
- the failure of suppliers to pay third parties under obligations for which we have potential contingent liabilities;
- the failure of counterparties to fulfill their delivery or purchase obligations; and
- the potential for adverse actions by rating agencies.

Rate regulation or challenges by shippers of the rates we charge on our petroleum pipeline system may reduce the amount of cash we generate.

The FERC regulates the tariff rates for interstate movements and state regulatory authorities regulate the tariff rates for intrastate movements on our petroleum pipeline system. 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 by the FERC 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. For example, in June 2012, HollyFrontier Refining & Marketing LLC (“HollyFrontier”) filed a complaint with the FERC alleging over-earning on the Osage pipeline in which we own a 50% interest and serve as operator. Osage and HollyFrontier have agreed to settle this matter, subject to FERC approval. The settlement agreement includes a one-time cash payment for reparations, a reduction of tariff rates and other concessions. The FERC and state regulatory authorities may also investigate tariff rates absent shipper complaint. If existing rates challenged by complaint are determined by the FERC or state regulatory authorities to be in excess of a just and reasonable level when taking into consideration our pipeline system's cost-of-service, those agencies could require the payment of reparations to complaining shippers.

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 is price indexing. We use this methodology to establish our rates in approximately one-third of our markets. 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 2010, the FERC established a new price index level of PPI-FG plus 2.65% for the five-year period beginning July 1, 2011. If the PPI-FG falls and our rates are at the ceiling level, we would be required to reduce our rates that are based on the FERC's price indexing methodology.

We establish rates in approximately two-thirds of our markets using the FERC's market-based ratemaking regulations. These regulations allow us to establish rates based on conditions in individual markets without regard to the index 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.

Any reduction in the indexed rates, removal of our ability to establish market-based rates or payment of reparations could have a material adverse effect on our results of operations and reduce the amount of cash we generate.

Changes in price levels could negatively impact our revenues, our expenses, or both, which could adversely affect our results from operations, our liquidity and our ability to pay quarterly 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 approximately one-third of the markets served by our petroleum pipeline system. For the five-year period beginning July 1, 2011, the indexing method provides for annual changes in rates by a percentage equal to the change in the PPI-FG plus 2.65%. This methodology could result in changes in our revenues that do not fully reflect changes in the costs we incur to operate and maintain our petroleum pipeline system. For example, our costs could increase more quickly or by a greater amount than the PPI-FG index plus 2.65% used by the current FERC methodology. Further, in periods of general price deflation, the PPI-FG index could fall, in which case we could be required 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 revenues 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, some of which may not be covered by insurance.

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 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. We are not fully insured against all risks related to our business, and the insurance we carry requires that we meet certain deductibles before we can collect for any losses we sustain. In addition, premiums and deductibles for our insurance policies have increased significantly, and could escalate further 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. 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.

Our operations are subject to extensive environmental, health, safety and other laws and regulations that impose significant costs and liabilities on us. These 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 Water Pollution Control Act, the Oil Pollution Act, 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, 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/or 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 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 under CERCLA, RCRA, the Water Pollution Control Act or analogous state laws for the remediation of contaminated areas. 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/or may not provide sufficient coverage in the event an environmental claim is made against us.

The terminal and pipeline facilities that comprise our petroleum pipeline system have been used for many years to transport, store or distribute petroleum products. 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 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 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 reauthorized funding for federal pipeline safety programs through 2015, 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. The Pipeline Hazardous Materials Safety Administration of the U.S. Department of Transportation has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. 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.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Among several such regulations, in May 2010, the EPA finalized its “tailoring rule,” determining which stationary sources of greenhouse gases are required to obtain permits and implement best available control technology standards on account of their greenhouse gas emission levels. Further, Congress has considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction. Such legislation would have established an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. The current administration supports legislation to reduce greenhouse gas emissions through an emission allowance system. As allowances under such a system would be expected to significantly escalate in cost over time, the net effect of any potential cap-and-trade legislation would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, if it occurs, may result in materially increased compliance and operating costs. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

The effect on our operations of CAA regulations, legislative efforts or related implementation rules that 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 by our pipelines or other facilities, 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.

In addition, some scientists have concluded that 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, droughts, floods and other climate events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

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 many 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/or 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 require 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 revenues and/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 affect on our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

We depend on refineries and petroleum pipelines owned and operated by others to supply our pipelines and terminals.

We depend on connections with refineries and petroleum pipelines owned and operated by third parties as a significant source of supply for our facilities. Outages at these refineries or reduced or interrupted throughput on these pipelines because of 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 petroleum pipeline system 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 petroleum pipeline system. The closure of a refinery that delivers product to or receives crude from our petroleum pipeline system could reduce the volumes we transport and the amount of cash we generate. Further, the closure of these or other refineries could result in companies electing to store and distribute refined petroleum products through their proprietary terminals, which could result in a reduction of our storage volumes.

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.

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 between 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 the systems compete. As a result, we could lose some or all of the volumes and associated revenues from these customers and we could experience difficulty in replacing those lost volumes and revenues. Because most 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.

Potential future acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and liabilities, incurring 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 distributions 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 because of unfamiliarity with new assets and the businesses associated with them and their markets, challenges in managing and/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 under applicable indemnification provisions.

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 affect on our results of operations or cash flows, 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.

We have begun numerous large expansion projects that have required and will continue to require us to make significant capital investments. We intend to finance those projects largely 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, if at all, until sometime after the projects are completed. As a result, our leverage will 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 and/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 and/or cost overruns. Any cost overruns or unanticipated delays in the completion or commercial development of these 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.

The amount and timing of distributions to us from our joint ventures is not entirely 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.

We participate in several joint ventures, in each of which our control of the joint venture is limited by 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. In addition, many activities of the joint ventures may only be authorized by agreement between us and the other owners of those joint ventures. In the case of Double Eagle Pipeline LLC, our joint venture co-owner serves as operator, and consequently we rely on our joint venture co-owner for many of the management functions of that joint venture. Without the cooperation of the other owners of those joint ventures, we may be unable to cause our joint ventures to take or not to take certain actions, even though those actions or in-actions may be in the best interest of us or the particular joint venture. If we are unable to agree with our joint venture co-owner on a significant matter, it 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 financial condition, results of operations or cash flows.

Moreover, subject to certain limitations in the respective joint venture agreements, any joint venture owner may sell, transfer or otherwise modify 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.

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 material reduction in the distributions we receive from our joint ventures could impair our results of operations, cash flows and our ability to pay 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 revenues, 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 petroleum pipeline system, 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 revenues and operating profit from blending activities. Any such reduction of our revenues or operating profit could have a material adverse effect on our results of operations, financial position, cash flows and 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 future targets of terrorist organizations. The threat of terrorist attacks has subjected our operations to increased risks. Any future 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 future 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.

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

As of December 31, 2012, we had $2.4 billion of fixed-rate debt outstanding (excluding unamortized discounts and premiums on debt issuances and the unamortized portion of fair value hedges). We expect to make floating-rate borrowings under our revolving credit facility as needed to partially finance future expansion capital spending. As a result, we 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.

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 law 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.

Cyber attacks that circumvent our security measures could disrupt our operations and result in increased costs.

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 affect 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.

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.

Tax Risks to Limited Partner Unitholders

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

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

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is 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 members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Such legislation could be reintroduced and amended prior to enactment in a manner that could affect us. 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. Because of widespread 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 because 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 will adopt 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 day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We 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 units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The Department of the Treasury and the IRS have issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Although existing publicly traded partnerships are entitled to rely on these proposed Treasury

Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued. Further, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury Regulations were issued, we may 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 that may result in a shift of income, gain, loss and deduction between our partners. The IRS may challenge this treatment, which could adversely affect the value of our limited partner units.

When we issue additional limited partner units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our partners. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between our partners, which may be unfavorable to certain unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their IRS Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Internal Revenue Code Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our partners.

A successful IRS challenge to these methods or allocations could adversely affect the amount 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 profit 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 23 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.

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

In July 2011, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act regarding a pipeline release in February 2011 in Texas. We have accrued $0.1 million for potential monetary sanctions related to this matter. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

In March 2012, we received a Notice of Probable Violation from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration for alleged violations related to the operation and maintenance of certain pipelines in Oklahoma and Texas. We have accrued approximately $0.1 million for potential monetary sanctions related to this matter. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

In April 2012, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in December 2011 in Nebraska. We have accrued $0.6 million for potential monetary sanctions related to this matter. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

In December 2012, we received a notice from the EPA that we may have potential liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party under Section 107(a) of the CERCLA Act of 1980. Currently, there is an ongoing removal action designed to stabilize the site, remove the immediate threat posed at the site and set the stage for a later more comprehensive action. Due to the timing of the EPA's notice, we are unable at this point, to reasonably estimate the amount of our potential liability, if any, related to this matter.

In January 2013, we received an information request from the EPA, pursuant to Section 308 of the Clean Water Act, regarding a diesel release in June 2012 in Kansas. We are currently preparing our response and evaluating environmental data to assess a potential accrual. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

In February 2010, a class action lawsuit was filed against us, ARCO Midcon L.L.C. and WilTel Communications, L.L.C. (“WilTel”). The complaint alleges that the property owned by plaintiffs and those similarly situated has been damaged by the existence of hazardous chemicals migrating from a pipeline easement onto the plaintiffs' property. We acquired the pipeline from ARCO Pipeline (“APL”) in 1994 as part of a larger transaction and subsequently transferred the property to WilTel. We are required to indemnify and defend WilTel pursuant to the transfer agreement. Prior to the acquisition of the pipeline from APL, the pipeline was purged of product. Neither we nor WilTel ever transported hazardous materials through the pipeline. A hearing on the plaintiff's Motion for Class Certification was held in the U.S. District Court for the Eastern District of Missouri in December 2012. The court has not yet rendered a decision on the issue of class certification. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

We are a party to various claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our future results of operations, financial position or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our limited partner units representing limited partnership interests are listed and traded on the New York Stock Exchange under the ticker symbol “MMP.” At the close of business on February 21, 2013, we had 226,679,438 limited partner units outstanding that were owned by approximately 117,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $34.44 on December 30, 2011 and $43.19 on December 31, 2012. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2011 and 2012 were as follows:

	2011*			2012*		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$30.29	$26.67	$0.38500	$36.87	$32.17	$0.42000
2nd	$31.55	$27.78	$0.39250	$36.46	$33.31	$0.47125
3rd	$30.93	$25.50	$0.40000	$44.25	$35.08	$0.48500
4th	$34.61	$28.69	$0.40750	$45.58	$39.06	$0.50000

* Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter. Per unit amounts have been restated for the two-for-one split of limited partner units completed in October 2012.

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 $0.50 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, 2007 and that all distributions or dividends were reinvested on a quarterly basis.

The information provided in this section is being furnished to, and not filed with, the Securities and Exchange Commission ("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 audited consolidated financial statements and related notes. 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 recognized in our accompanying consolidated financial statements.

In August 2012, our general partner's board of directors approved a two-for-one split of our limited partner units, which was completed on October 12, 2012. We have retrospectively restated all unit and per unit amounts associated with this split in this report for each respective period presented.

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. A reconciliation of DCF to net income, the nearest comparable GAAP measure, is included in the following tables.

In addition to DCF, the non-GAAP measures of operating margin (in the aggregate and by segment) and adjusted EBITDA are presented in the following tables. We compute the components of operating margin and adjusted EBITDA using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit and net income to adjusted EBITDA, which are the nearest comparable GAAP financial measures, are included in the following tables. See Note 15–Segment Disclosures 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 the investment community to assess the financial results of an entity.

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

	Year Ended December 31,				
	2008	2009	2010	2011	2012
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$638,810	$678,945	$793,599	$893,369	$970,744
Product sales revenues	574,095	334,465	763,090	854,528	799,382
Affiliate management fee revenues	733	761	758	770	1,948
Total revenues	1,213,638	1,014,171	1,557,447	1,748,667	1,772,074
Operating expenses	264,871	257,635	282,212	306,415	328,454
Product purchases	436,567	280,291	668,585	706,270	657,108
Gain on assignment of supply agreement	(26,492)	—	—	—	—
Equity earnings	(4,067)	(3,431)	(5,732)	(6,763)	(2,961)
Operating margin	542,759	479,676	612,382	742,745	789,473
Depreciation and amortization expense	86,501	97,216	108,668	121,179	128,012
G&A expense	73,302	84,049	95,316	98,669	109,403
Operating profit	382,956	298,411	408,398	522,897	552,058
Interest expense, net	50,479	69,187	93,296	105,634	111,679
Debt placement fee amortization	767	1,112	1,401	1,831	2,087
Other (income) expense, net	(380)	(24)	750	—	—
Income before provision for income taxes	332,090	228,136	312,951	415,432	438,292
Provision for income taxes	1,987	1,661	1,371	1,866	2,622
Net income	$330,103	$226,475	$311,580	$413,566	$435,670
Net income allocation:[(a)]					
Non-controlling owners' interest	$244,430	$99,729	$(397)	$(63)	$—
Limited partner interests	87,733	126,746	311,977	413,629	435,670
General partner interest	(2,060)	—	—	—	—
Net income	$330,103	$226,475	$311,580	$413,566	$435,670
Basic and diluted net income per limited partner unit	$1.11	$1.11	$1.42	$1.83	$1.92
Balance Sheet Data:					
Working capital (deficit)	$(29,644)	$94,571	$109,536	$301,135	$307,658
Total assets	$2,600,708	$3,163,148	$3,717,900	$4,045,001	$4,420,067
Long-term debt	$1,083,485	$1,680,004	$1,906,148	$2,151,775	$2,393,408
Owners' equity	$1,254,132	$1,196,354	$1,469,571	$1,463,403	$1,515,702
Cash Distribution Data:					
Cash distributions declared per MMP unit[(b)]	$1.39	$1.42	$1.48	$1.59	$1.88
Cash distributions paid per MMP unit[(b)]	$1.36	$1.42	$1.45	$1.56	$1.78

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	Year Ended December 31,				
	2008	2009	2010	2011	2012
	(in thousands, except operating statistics)				
Other Data:					
Operating margin (loss):					
Petroleum pipeline system	$428,903	$361,598	$480,781	$572,198	$592,901
Petroleum terminals	101,713	110,573	132,748	160,350	176,985
Ammonia pipeline system	8,660	3,666	(4,156)	7,279	16,632
Allocated partnership depreciation costs[(c)]	3,483	3,839	3,009	2,918	2,955
Operating margin	$542,759	$479,676	$612,382	$742,745	$789,473
Distributable cash flow:					
Net income	$330,103	$226,475	$311,580	$413,566	$435,670
Interest expense, net	50,479	69,187	93,296	105,634	111,679
Depreciation and amortization expense[(d)]	87,268	98,328	110,069	123,010	130,099
Equity-based incentive compensation expense[(e)]	931	6,123	15,499	10,243	8,038
Asset retirements and impairments	7,180	5,529	1,062	8,599	12,622
Commodity-related adjustments[(f)]	(13,787)	24,262	7,751	(22,370)	12,894
Product supply agreement gains[(g)]	(26,919)	—	—	—	—
Other[(h)]	(3,331)	5,685	(1,582)	(2,504)	4,850
Adjusted EBITDA	431,924	435,589	537,675	636,178	715,852
Interest expense, net	(50,479)	(69,187)	(93,296)	(105,634)	(111,679)
Maintenance capital (net of reimbursements)	(43,232)	(37,999)	(44,620)	(70,002)	(64,396)
Distributable cash flow	$338,213	$328,403	$399,759	$460,542	$539,777
Operating Statistics:					
Petroleum pipeline system:					
Transportation revenue per barrel shipped[(i)]	$1.193	$1.205	$1.160	$1.082	$1.086
Volume shipped (million barrels):[(j)]					
Refined products:					
Gasoline	152.7	169.9	194.3	208.9	223.7
Distillates	114.8	100.2	122.9	136.0	136.7
Aviation fuel	22.2	19.8	22.6	25.3	21.5
Liquefied petroleum gases	6.2	5.8	5.0	4.9	8.5
Crude oil	—	—	14.7	43.2	72.0
Total volume shipped[(i)]	295.9	295.7	359.5	418.3	462.4
Petroleum terminals:					
Storage terminal average utilization (million barrels per month)	21.4	23.5	25.8	32.1	34.5
Inland terminal throughput (million barrels)	108.1	109.8	114.7	115.6	116.2
Ammonia pipeline system:					
Volume shipped (thousand tons)	822	643	462	727	770

(a) In September 2009, we simplified our capital structure wherein our general partner became our wholly-owned subsidiary, our requirement to pay incentive distribution rights was eliminated and we acquired all of the non-controlling owners' interests that existed at that time. Following the simplification, all of our net income was allocated to our limited partners until the formation of Magellan Crude Oil, LLC ("MCO") in 2010, which was partially owned by a private investment group. In February 2011, we acquired all of the non-controlling owners' interest in MCO.

(b) Cash distributions declared represent distributions declared associated with 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.

(c) Certain assets were contributed to us and were recorded as property, plant and equipment at the partnership level. The associated depreciation expense was allocated to our various business segments, which in turn recognized these allocated costs as operating expense, reducing segment operating margins by these amounts.

(d) Includes debt placement fee amortization.

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

(f) See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Distributable Cash Flow for details of these commodity-related adjustments.

(g) In October 2004, as part of our acquisition of a pipeline system, we assumed a third-party supply agreement. Because the expected profits from this supply agreement were below the fair value of the associated tariff-based shipments on the acquired pipeline, we recognized a liability for the difference. From 2004 until the first quarter of 2008, we amortized a portion of this liability to revenues. We adjusted these non-cash revenue credits out of our DCF calculations. In 2008, we assigned this supply agreement to a separate third party and recognized a non-cash gain on that transaction of $26.5 million, which we also eliminated from our DCF calculations.

(h) Other primarily includes adjustments for equity investment earnings and distributions and non-controlling owners' interests losses included in net income during 2010 and 2011. Years 2008 and 2009 also include expense paid by (credited to) a former affiliate.

(i) We acquired crude oil and refined products pipelines in South Texas during September 2010. The volumes on these pipelines travel short distances and we charge a significantly lower tariff rate than we do for the rest of our pipeline systems. Volumes have increased substantially on these South Texas pipelines, impacting our average transportation revenue per barrel shipped and more than offsetting rate increases on our other pipeline systems.

(j) Excludes capacity leases.

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. As of December 31, 2012, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 49 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our partnership. 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, 2012.

Recent Developments

BridgeTex Pipeline Company, LLC. In November 2012, we formed BridgeTex Pipeline Company, LLC ("BridgeTex"), a joint venture with affiliates of Occidental Petroleum Corporation. BridgeTex was formed to construct and operate the BridgeTex pipeline, a 400-mile pipeline capable of transporting 300,000 barrels per day of Permian Basin crude oil from Colorado City, Texas for delivery to our East Houston, Texas terminal; a 50-mile pipeline between East Houston and Texas City, Texas; and approximately 2.6 million barrels of storage. We expect to spend approximately $600 million for our 50% ownership interest in BridgeTex. We are serving as construction manager and will serve as operator of BridgeTex upon its completion, which is expected in mid-2014.

Sale of Claim Against MF Global Inc. In October 2011, MF Global Holdings Ltd., the parent of MF Global Inc. ("MF Global"), filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy laws, and a trustee was appointed to oversee the liquidation of MF Global under the Securities Investor Protection Act. At that time, MF Global served as our sole clearing agent for New York Mercantile Exchange ("NYMEX") futures contracts. We transferred our existing trading positions at MF Global to a new clearing agent in November 2011. As of the date of transfer of our account, MF Global owed us $29.4 million. We subsequently received $23.6 million as partial payment of the amount owed to us. In December 2012, we sold our remaining claim of $5.8 million to a third party for $5.4 million. The buyer of the claim assumed the risk of ultimate collectability of the claim subject to the accuracy of typical representations and warranties from us related to the claim. We charged the $0.4 million loss we sustained from the sale of this receivable to operating expense.

Debt Offering. In November 2012, we issued $250.0 million of 4.20% notes due December 1, 2042 in an underwritten public offering. The notes were issued for the discounted price of 99.3% of par. We have used or intend to use the net proceeds from this offering of approximately $245.8 million, after underwriting discounts and offering expenses, for general partnership purposes, including capital expenditures and investments in interest-bearing securities or accounts.

Cash Distribution. In January 2013, the board of directors of our general partner declared a quarterly cash distribution of $0.50 per unit for the period of October 1, 2012 through December 31, 2012. This quarterly cash distribution was paid on February 14, 2013 to unitholders of record on February 6, 2013. The total distributions paid on 226.7 million limited partner units outstanding was $113.3 million.

Pipeline Acquisition. On February 22, 2013, we announced an agreement to acquire approximately 800 miles of refined petroleum products pipeline from Plains All American Pipeline, L.P. for $190 million. Subject to regulatory approvals, we expect the acquisition to close during the second quarter of 2013. We expect to fund the acquisition with cash on hand and, if necessary, with borrowings under our revolving credit facility.

Overview

Our petroleum pipeline system and petroleum terminals generate the majority of our operating margin from the transportation and storage services we provide to our customers. The revenues generated from these businesses are significantly influenced by demand for refined petroleum products and crude oil. In addition, we generate operating margin from commodity-related activities. Operating expenses are principally fixed costs related to routine maintenance and system integrity as well as field and support personnel. Other costs, including power, fluctuate with volumes transported on our pipeline and stored in our terminals.

A prolonged period of high petroleum prices or a recessionary economic environment could lead to a reduction in demand and result in lower shipments on our pipeline system and reduced demand for our terminal services. Fluctuations in the prices of petroleum products impact the amount of cash our petroleum pipeline system generates from its blending and fractionation activities. In addition, increased maintenance regulations, higher power costs and higher interest rates could decrease the amount of cash we generate. See Item 1A—Risk Factors for other risk factors that could impact our results of operations, financial position and cash flows.

Petroleum Pipeline System. Our petroleum pipeline system is comprised of a common carrier pipeline that provides transportation, storage and distribution services for petroleum products in 14 states from Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Through direct refinery connections and interconnections with other interstate pipelines, our petroleum pipeline system can access approximately 44% of U.S. refining capacity. In 2012, the petroleum pipeline system generated 73% of its revenues, excluding the sale of petroleum products, primarily through transportation tariffs for petroleum volumes shipped. These tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All interstate transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission (“FERC”). The pipeline also earns revenues from non-tariff based activities, including leasing pipeline and storage tank capacity to shippers and by providing data services and product services such as ethanol and biodiesel unloading and loading, additive injection, terminalling, custom blending and laboratory testing.

Substantially all of the shipments on our pipeline system are for third parties, and we do not take title to these products. We do take title to products related to our petroleum products blending and fractionation activities and in connection with certain transactions involving the operation of our pipeline system and terminals.

During 2012, in conjunction with our Crane-to-Houston pipeline reversal project, we discontinued refined products transportation service on our Houston-to-El Paso pipeline section and shifted these volumes to a nearby pipeline section which we own. The associated linefill products we held title to on the Houston-to-El Paso pipeline were either sold or transferred to our other pipelines to fulfill product shortage positions on those systems. The $37.0 million decrease in the inventory balance between December 31, 2011 and 2012 was primarily attributable to these product sales and transfers. Although our petroleum products blending, fractionation and other commodity-related activities generate significant revenues from the sale of petroleum products and the associated gains/losses from the applicable associated derivative agreements, we believe the product margin from these activities, which takes into account the related product purchases, better represents its importance to our results of operations.

Petroleum Terminals. Our petroleum terminals segment is comprised of storage terminals and inland terminals, which store and distribute petroleum products throughout 13 states. Our storage terminals are comprised of six facilities that have marine access and are located near major refining hubs along the U.S. Gulf and East Coasts. We also have a crude oil terminal in Cushing, Oklahoma, one of the largest crude oil trading hubs in the U.S. These storage terminals principally serve refiners, marketers and traders. We earn revenues at our storage terminals primarily from storage and throughput fees. Our inland terminals are part of a distribution network located principally throughout the Southeastern U.S. These inland terminals are connected to large, third-party interstate pipelines and are utilized by retail suppliers, wholesalers and marketers to transfer gasoline and other petroleum products from these pipelines to trucks, railcars or barges for delivery to their final destination. We earn revenues at our inland terminals primarily from fees we charge based on the volumes of refined petroleum products distributed from these locations and from ancillary services such as additive injections and ethanol blending.

Ammonia Pipeline System. Our ammonia pipeline system transports and distributes ammonia from production facilities in Texas and Oklahoma to various distribution points in the Midwest for use as an agricultural fertilizer. We generate revenues principally from volume-based fees for the transportation of ammonia on our pipeline system.

Growth Projects

We remain focused on growth and have significantly increased our operations over the past several years through organic growth projects and acquisitions that expand or upgrade our existing facilities. Our current expansion projects are driven by:

- demand for storage because of volatility of petroleum products prices, which has provided significant opportunity for us to build tankage along our petroleum pipeline system and at our storage terminals, backed by long-term customer commitments; and

- demand for crude oil and condensate storage and transportation services, which has provided the opportunity for us to reverse and convert to crude oil service a significant portion of our Houston-to-El Paso pipeline segment (also known as the Longhorn pipeline), begin construction of 450 miles of crude oil pipeline and related infrastructure, in which we will hold a 50% ownership interest, and significantly expand our crude oil and condensate storage and transportation infrastructure in the Houston and Corpus Christi areas.

We spent $198.9 million and $364.7 million on acquisitions and growth projects during 2011 and 2012, respectively. Further, we currently expect to spend approximately $700.0 million in 2013 on projects now underway, with additional spending of approximately $290.0 million in 2014 to complete these projects. These expansion capital estimates exclude potential acquisitions or spending on more than $500.0 million of other potential growth projects in earlier stages of development.

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") costs, which management does not consider when evaluating the core profitability of our operations. 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 product purchases are determined in accordance with GAAP.

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

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$637.8	$691.7	$53.9	8 %
Petroleum terminals	235.0	254.1	19.1	8 %
Ammonia pipeline system	23.6	27.7	4.1	17 %
Intersegment eliminations	(3.0)	(2.8)	0.2	7 %
Total transportation and terminals revenues	893.4	970.7	77.3	9 %
Affiliate management fee revenues	0.8	2.0	1.2	150 %
Operating expenses:				
Petroleum pipeline system	199.9	225.1	(25.2)	(13)%
Petroleum terminals	93.0	95.2	(2.2)	(2)%
Ammonia pipeline system	16.4	11.1	5.3	32 %
Intersegment eliminations	(2.9)	(2.9)	—	— %
Total operating expenses	306.4	328.5	(22.1)	(7)%
Product margin:				
Product sales	854.5	799.4	(55.1)	(6)%
Product purchases	706.3	657.1	49.2	7 %
Product margin [a]	148.2	142.3	(5.9)	(4)%
Equity earnings	6.8	3.0	(3.8)	(56)%
Operating margin	742.8	789.5	46.7	6 %
Depreciation and amortization expense	121.2	128.0	(6.8)	(6)%
G&A expense	98.7	109.4	(10.7)	(11)%
Operating profit	522.9	552.1	29.2	6 %
Interest expense (net of interest income and interest capitalized)	105.6	111.7	(6.1)	(6)%
Debt placement fee amortization	1.8	2.1	(0.3)	(17)%
Income before provision for income taxes	415.5	438.3	22.8	5 %
Provision for income taxes	1.9	2.6	(0.7)	(37)%
Net income	$413.6	$435.7	$22.1	5 %
Operating Statistics				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.082	$1.086		
Volume shipped (million barrels):[b]				
Refined products:				
Gasoline	208.9	223.7		
Distillates	136.0	136.7		
Aviation fuel	25.3	21.5		
Liquefied petroleum gases	4.9	8.5		
Crude oil	43.2	72.0		
Total volume shipped	418.3	462.4		
Petroleum terminals:				
	32.1	34.5		

Storage terminal average utilization (million barrels per month)		
Inland terminal throughput (million barrels)	115.6	116.2
Ammonia pipeline system:		
Volume shipped (thousand tons)	727	770

(a) Product margin does not include depreciation or amortization expense.
(b) Excludes capacity leases.

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Transportation and terminals revenues increased by $77.3 million, resulting from:

- an increase in petroleum pipeline system revenues of $53.9 million resulting from:

  an 11% increase in transportation volumes, mainly due to increases in crude oil and gasoline shipments. Crude oil shipments increased 67% resulting from deliveries to additional locations that have been connected to our pipeline system and increased deliveries to existing customers. Gasoline volumes increased 7% attributable primarily to higher volumes on our South Texas pipeline system due to increased demand and new incentive tariffs put in place to attract volumes;

  a slight increase in the average per-barrel tariff rate, going from $1.082 to $1.086, as the tariff rate increases we implemented in July 2011 and 2012 were mostly offset by more crude oil and South Texas movements, which ship at a lower rate than our other shipments; and

  higher leased storage revenue due to new tanks added to our system during 2011 and 2012.

- an increase in petroleum terminals revenues of $19.1 million primarily due to leasing tanks constructed throughout 2011, including new crude oil storage at Cushing, Oklahoma, and higher rates at our marine terminals; and

- an increase in ammonia pipeline system revenues of $4.1 million primarily because of higher average rates resulting from our mid-year tariff increases and more volumes transported as 2011 shipments were negatively impacted by certain hydrostatic testing completed that year.

Operating expenses increased $22.1 million, resulting from:

- an increase in petroleum pipeline system expenses of $25.2 million primarily due to lower product overages (which reduce operating expenses), additional asset integrity work, an increase in property taxes, higher personnel costs and higher losses on various asset retirements and replacements, which were partially offset by impairment charges in 2011 for a system terminal we closed and a potential air emission fee accrual in 2011;

- an increase in petroleum terminals expenses of $2.2 million primarily due to higher losses on various asset retirements and replacements, higher personnel costs and higher operating taxes, partially offset by an accrual recognized in 2011 for potential air emission fees with no corresponding charge in the current period; and

- a decrease in ammonia pipeline system expenses of $5.3 million primarily due to lower asset integrity costs as 2011 included expenses for certain hydrostatic testing conducted during that year.

Product sales revenues primarily resulted from our petroleum products blending activities, terminal product gains and transmix fractionation. For 2011 and a portion of 2012, product sales revenues also resulted from product marketing and linefill management associated with our Houston-to-El Paso pipeline section. We utilize NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in the future. The period change in the mark-to-market value of these contracts that are not designated as hedges for accounting purposes, the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment and any ineffectiveness of NYMEX contracts that qualify for hedge accounting treatment are also included in product sales revenues. We use butane futures agreements to hedge against changes in the price of butane we expect to purchase in future periods. The period change in the mark-to-market value of these futures agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin decreased $5.9 million between periods primarily due to unrealized losses on NYMEX contracts in 2012 (compared to unrealized gains in 2011) resulting from increasing product prices in the current year, offset by increased volumes and profits from our petroleum products blending activities primarily as a result of expanding our blending operations, particularly at our East Houston facility. See Other Items–Commodity Derivative Agreements–Product Sales Revenues below for more information about our NYMEX contracts.

Equity earnings decreased $3.8 million from 2011 primarily due to an anticipated settlement of a tariff claim against Osage Pipe Line Company, LLC ("Osage") (see Note 16—Commitments and Contingencies—Osage Complaint in the Notes to Consolidated Financial Statements for more information regarding this claim).

Depreciation and amortization expense increased $6.8 million in 2012 primarily due to expansion capital projects placed into service over the past two years.

G&A expense increased $10.7 million between periods primarily due to higher personnel costs and an increase in long-term equity-based incentive compensation costs resulting from above-target payout estimates and a higher price for our limited partner units.

Interest expense, net of interest income and interest capitalized, increased $6.1 million in 2012. Our average outstanding debt increased to $2.2 billion for 2012 from $2.1 billion for 2011 primarily due to borrowings for expansion capital expenditures, including $250.0 million of 4.25% senior notes issued in August 2011 and $250.0 million of 4.20% senior notes issued in November 2012. Our weighted-average interest rate of 5.3% at December 31, 2012 was essentially unchanged from our weighted-average interest rate at December 31, 2011.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2011

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2010	2011	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$584.0	$637.8	$53.8	9%
Petroleum terminals	196.7	235.0	38.3	19%
Ammonia pipeline system	14.9	23.6	8.7	58%
Intersegment eliminations	(2.0)	(3.0)	(1.0)	(50)%
Total transportation and terminals revenues	793.6	893.4	99.8	13%
Affiliate management fee revenues	0.8	0.8	—	—%
Operating expenses:				
Petroleum pipeline system	191.0	199.9	(8.9)	(5)%
Petroleum terminals	75.2	93.0		