MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 27, 2012

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, 2011
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	74121-2186
(Address of principal executive offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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, 2011 was $6,720,057,505.

As of February 23, 2012, there were 113,100,436 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 2012 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

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 (“MMP GP”), 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.

Crude Oil and Condensate Development
During 2011, we took significant steps to expand our crude oil transportation and storage assets. We completed the construction of more than 4 million barrels of crude oil storage in Cushing, Oklahoma during the year, bringing our total crude oil storage in Cushing to 12 million barrels, solidifying our position as one of the largest owners of crude oil storage in the strategic Cushing crude oil hub.
We also decided to reverse and convert a portion of our Houston-to-El Paso, Texas pipeline from refined products to crude oil service in order to provide crude oil deliveries from its origin point in Crane, Texas to our East Houston, Texas terminal for further delivery to refineries or third-party pipelines along the Houston ship channel and Texas City, Texas through our existing crude oil distribution system. This reversed pipeline system is expected to have an initial capacity of 135,000 barrels per day, cost approximately $245 million to reverse and convert and be operational by early 2013. We have received long-term committed volumes for a portion of the initial capacity of this pipeline. Capacity could be expanded to up to 225,000 barrels per day if warranted by additional commitments.
In addition, in December 2011, we announced the formation of a joint venture to deliver Eagle Ford shale condensate to our Corpus Christi, Texas terminal. We have a 50% ownership interest in this joint venture, with Copano Energy, L.L.C. ("Copano") owning the other 50% interest. The joint venture, known as Double Eagle Pipeline LLC, will construct and own approximately 140 miles of pipeline to connect to an existing 50-mile pipeline segment owned by Copano, enabling delivery of approximately 100,000 barrels per day of condensate from the Eagle Ford shale formation to our Corpus Christi terminal. Copano will oversee the construction of the pipeline and will serve as operator once pipeline operations commence. This project is supported by long-term customer commitments and is expected to be fully operational by early 2013. In conjunction with this project (but separate from the joint venture with Copano), we are making enhancements to our Corpus Christi terminal, including the construction of 500,000 barrels of dedicated condensate storage and a dedicated dock delivery pipeline. This project will cost approximately $100 million, which includes $75.0 million for our portion of the pipeline construction and $25.0 million for tankage and other infrastructure changes at our Corpus Christi terminal.
(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, 2011, our asset portfolio consists of:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 50 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.

1

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 2011" published by the Energy Information Administration ("EIA"), the Gulf Coast region accounted for approximately 45% of total U.S. daily refining capacity and 85% of U.S. refining capacity expansion from 2001 to 2011. The growth in Gulf Coast refining capacity has resulted in part from consolidation in the petroleum industry to take advantage of economies of scale from operating larger refineries. The role of Gulf Coast refiners as well as imports should become even more significant going forward 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 13-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 50 terminals. The products transported on our pipeline system are largely transportation fuels and in 2011 were comprised of 50% gasoline, 33% distillates, 10% crude oil and 7% aviation fuel and LPGs. Refined product and LPG shipments originate on our pipeline system from direct connections to refineries, at 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 refineries, crude oil terminals and through interconnections with other interstate 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,		
	2009	2010	2011
Percent of consolidated revenues	80%	85%	84%
Percent of consolidated operating margin	75%	79%	77%
Percent of consolidated total assets	73%	71%	67%

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 2012 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 imports of refined petroleum products 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 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 are being developed that will provide access to a broader group of origins and refineries in the Houston refining region.

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

	Year Ended December 31,		
	2009	2010	2011
Shipments (thousand barrels):			
Refined products			
Gasoline	169,873	194,338	208,852
Distillates	100,214	122,929	136,003
Aviation fuel	19,843	22,612	25,245
LPGs	5,770	4,949	4,927
Crude oil	—	14,658	43,239
Total shipments	295,700	359,486	418,266
Capacity leases	29,821	27,084	30,672
Total shipments, including capacity leases	325,521	386,570	448,938
Daily average (thousand barrels)	892	1,059	1,230

The increase in total shipments for 2010 and 2011 was primarily due to acquisitions and growth projects completed during the last two fiscal years.

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,

3

if necessary.

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 more than 44% of the refinery capacity in the continental U.S. Most 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 reverse and convert a portion of our Houston-to-El Paso pipeline segment (See Pipeline Conversion to Crude Service in Item 7), we take title to the linefill related to this pipeline section and a portion of the petroleum products we currently transport 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 2011, our petroleum pipeline system generated 72% 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 34 of our pipeline system's 50 terminals. Revenues from terminalling and storage at our other 16 terminals are at privately-negotiated rates.

In 2011, our petroleum pipeline system generated the remaining 28% of its revenues, excluding product sales revenues, from leasing pipeline and storage tank capacity to shippers and from providing product and other 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 also receive a fee for operating a 135-mile pipeline (in which we have 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.

Product revenues for the petroleum pipeline system primarily result from our petroleum products blending and transmix fractionation activities and from linefill management and product marketing associated with our Houston-to-El Paso pipeline section. 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 75% of the total product margin for the petroleum pipeline system during 2011. If the differential between the cost of 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, back into its original components. We purchase transmix from third parties and sell the resulting separated petroleum products. We also purchase petroleum products for shipment on the Houston-to-El Paso pipeline section to facilitate product shipments on the pipeline. We sell these products in the El Paso, Texas wholesale market. Product margin from all of these activities was $44.2 million, $81.3 million and $126.8 million for the years ended December 31, 2009, 2010 and 2011, 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 generally accepted accounting principles. 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 and hold 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, fractionation and pipeline linefill management 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, fractionation and pipeline linefill activities.

Facilities. Our petroleum pipeline system consists of an approximate 9,600-mile pipeline and 50 terminals and includes approximately 39 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 2011, approximately 59% of the petroleum products transported on our petroleum pipeline system originated from 13 direct refinery connections and 41% originated from interconnections 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
BP	Texas City, TX
Calumet Specialty Products	Superior, WI
CVR Energy	Coffeyville, KS
CVR Energy	Wynnewood, OK
ConocoPhillips	Ponca City, OK
Flint Hills Resources (Koch)	Pine Bend, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
National Cooperative Refining Association	McPherson, KS
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
Cenex	Fargo, ND	Laurel, MT refinery
ConocoPhillips	Kansas City, KS; Denver, CO	Borger, TX 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
Shell	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries
Crude:		
Speed Junction	Houston, TX	Various Houston, TX terminals and two pipelines along the Houston ship channel
Genoa Junction	Houston, TX	Two pipelines near the Houston ship channel

5

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 by shippers in exchange for reduced tariff rates or capital expansion commitments on our part. For 2011, approximately 50% of the shipments on our pipeline system were subject to these agreements. The average remaining life of these contracts was approximately 4 years as of December 31, 2011, with remaining terms of up to 14 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, 2011, 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, 2011 represented 52% of total revenues for our petroleum pipeline system and 62% 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. Our facilities receive products from pipelines and distribute them to third parties at the terminals, which in turn deliver them to end-users such as retail outlets. Because 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,		
	2009	2010	2011
Percent of consolidated revenues	18%	14%	15%
Percent of consolidated operating margin	23%	22%	22%
Percent of consolidated total assets	25%	27%	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, Marrero and Gibson, Louisiana and Galena Park and Corpus Christi, 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.

Customers and Contracts. We have long-standing relationships with oil refiners, suppliers and traders at our facilities. During 2011, approximately 97% of our storage terminal capacity was utilized. As of December 31, 2011, approximately 95% of our usable storage capacity was under contracts with remaining terms in excess of one year or that renew on an annual basis. The average remaining life of these contracts was approximately 4 years as of December 31, 2011. 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 additional 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. We wholly own 25 of the 27 terminals in our portfolio. 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 2011, 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,		
	2009	2010	2011
Percent of consolidated revenues	2%	1%	1%
Percent of consolidated operating margin	1%	(1)%	1%
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 to the 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, to store ammonia for future use and to 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, 2011 through June 30, 2012 are 550,000 tons, although our customers have typically shipped more than the 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.

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 2009, 2010 or 2011. 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, which is included in our petroleum pipeline system segment. In general, accounts receivable from these customers are due within 3 days of sale. We believe that other companies would purchase the petroleum products from us if these customers were unable or unwilling to do so.

	Year Ended December 31,		
	2009	2010	2011
Customer A	11%	11%	21%
Customer B	5%	13%	8%
Total	16%	24%	29%

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, like some of those charged for 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%. Approximately 35% of our petroleum pipeline system is subject to this annual indexing methodology. 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 65% 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.

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.

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 $32.8 million and $49.6 million at December 31, 2010 and December 31, 2011, 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 paid over the next ten years.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $2.2 million and $7.7 million at December 31, 2010 and December 31, 2011, 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 CAA requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas if the designated area within the state did not meet its attainment deadline. Imposition of the fee is mandated for each calendar year after the attainment date until the area is redesignated as an attainment area for ozone. 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”) drafted a “Failure to Attain Rule” (the “Rule”) to implement the requirements of CAA 185. The Rule was scheduled to be final in the spring of 2010 and would have provided for the collection of an annual failure to attain fee for emissions from calendar year 2008 forward. Under the Rule, the annual fees to be paid by entities within the

Houston-Galveston non-attainment area would have been determined by the emissions from a facility that exceed an established baseline for each entity. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule.

In January 2010, the EPA issued guidance for states developing fee programs under CAA 185. In response to and based on the standards in the EPA's guidance, the TCEQ suspended the draft Rule and submitted a request for a determination by the EPA (a "Termination Determination") that the Houston-Galveston Region no longer qualified as a severe non-attainment area. Had the TCEQ's request for a Termination Determination been approved by the EPA, the requirement to assess a CAA 185 fee would have been terminated. Subsequent to the TCEQ's request for a Termination Determination, the Natural Resource Defense Counsel submitted a petition in federal court challenging the legality of the EPA's guidance. Based upon the EPA's belief and assertion that the guidance would be sustained in federal court, management determined the probability of the assessment of an annual fee for the Houston-Galveston area was remote.

In July 2011, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in the National Resource Defense Counsel case vacating the EPA's January 2010 guidance memorandum on states' CAA 185 equivalent programs. As a result of the court's ruling, the EPA has instructed the TCEQ that it is unable to approve the Termination Determination request.

Based on the recent court decisions and statements by the EPA, management believes that it is probable that the TCEQ will move forward with its CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility that we will not be assessed any CAA 185 fees at all. However, management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston area facilities and estimates that the range of fees that could be assessed to us for the periods from 2007 through 2010 to be between $6.4 million and $13.7 million. During 2011, after multiple discussions with the TCEQ, we recognized our best estimate of this liability, or $8.9 million, which we recorded as a long-term environmental liability. Additionally during 2011, we accrued $0.8 million for estimated fees associated with 2011 ongoing operations and $1.0 million related to an incident involving the buildup of excess water on the top of floating roof tanks, both of which were recorded as a long-term environmental liability.

Carbon Dioxide Emission Standards. The EPA has set a May 2013 compliance date for the reduction of carbon dioxide from the exhausts of large stationary engines. The EPA rule generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance; however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. A portion of our petroleum pipeline system uses engines to provide power to our pipeline pumps that are subject to the EPA rule, and our maintenance capital estimates include funding to comply with the EPA rule. Initial efforts to reduce emissions with catalytic converters have not been successful, and has led to our request of a compliance extension to the EPA. If we do not receive an extension, or are not able to modify or replace these engines by May 2013, sections of our petroleum pipeline system could experience capacity reductions or we could be assessed 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 determined that one of our facilities storing butane meets their security risk screening threshold and is regulated under DHS's 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. With regard to gasoline storage facilities, the DHS has decided to delay final security risk determinations and issued a notice in the Federal Register asking for comments on including gasoline as a chemical of interest under CFATS. 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 can 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 oil and 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 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, including the American Clean Energy and Security Act of 2009, passed by the U.S. House of Representatives in June 2009 and a similar bill in the U.S. Senate. Either bill 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 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, to permit access to and copying of records and to 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.

Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires 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 operations and costs of transportation service.

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 are revocable at the election of the grantor. 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 a failure to obtain all consents, permits or authorizations will not have a material adverse effect on the operation of our business.

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, 2011, we had 1,297 employees. At December 31, 2011, the labor force of 566 employees assigned to our petroleum pipeline system was concentrated in the central U.S. Approximately 40% of these employees were represented by the United Steel Workers ("USW"). Our collective bargaining agreement with the USW expired January 31, 2012 and we are operating under an extension while negotiations are underway with the USW. The labor force of 275 employees assigned to our petroleum terminals operations at December 31, 2011, was primarily located in the southeastern and Gulf Coast regions of the U.S. Approximately 10% of these employees were represented by the International Union of Operating Engineers (“IUOE”) and covered by a collective bargaining agreement that expires October 31, 2013. At December 31, 2011, the labor force of 19 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 consider carefully 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 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. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to pay quarterly distributions at the current level for each quarter. Our ability to pay quarterly distributions depends primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, we may pay cash distributions during periods when we record net losses and may be unable to pay cash distributions during periods when we record net income.

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 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 November 2011 the National Highway Traffic Safety Administration and the U.S. Environmental Protection Agency ("EPA") proposed standards for passenger cars and light trucks manufactured in model years beginning in 2017 that would require significant increases in fuel efficiency. The proposed standards are intended to reduce demand for petroleum products, and if implemented these or similar standards could reduce demand for our services; and

- an increase in the use of alternative fuel sources, such as ethanol, biodiesel, fuel cells and solar, electric and battery-powered engines. Current laws will require a significant increase in the quantity of ethanol and biodiesel used in transportation fuels between now and 2022. Such an increase 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 our leased storage at our storage terminals and from leased storage 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, regulatory, accounting 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. In addition, we own linefill inventory required for the operation of portions of our pipeline system, and we purchase and sell petroleum products in connection with the management of that inventory. 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 would 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 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 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. We generally do not retain sufficient cash flow to finance these projects and acquisitions internally, and consequently the execution of our growth strategy requires regular access to outside sources of capital. Any limitations on our access to capital on satisfactory terms will impair our ability to execute this strategy. Similarly, we generally do not retain sufficient cash flow to repay our indebtedness when it matures and will rely on new capital to refinance these obligations. 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, significant increases in interest rates, increases in the risk premium required by investors, generally, or 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 a successful challenge to 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 newly filed 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. 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 35% 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 65% 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 35% 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 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. We are not fully insured against all risks related to our business. In addition, as a result of market conditions or of losses experienced by us or by other companies, premiums for our insurance policies could increase significantly. 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 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 leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines or our storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damage, 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 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 reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires 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 operations and costs of transportation service.

Our customers are also subject to extensive laws and regulations that affect their businesses, and new laws or regulations could materially 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 or are making significant investments in crude oil and and condensate storage and transportation projects that 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, including the American Clean Energy and Security Act of 2009, passed by the U.S. House of Representatives in June 2009 and a similar bill in the U.S. Senate. Either bill 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 regulations 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, among other things, 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. 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. Any significant increase in these expenditures could materially adversely affect 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 refineries could result in these 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, creating 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.

Acquisitions and business expansions involve numerous risks, including 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 new geographic areas 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.

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

We have begun or anticipate beginning numerous expansion projects which will require us to make significant capital investments. 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. The amount of time and investment necessary to complete these projects could 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. Any such cost overruns or unanticipated delays in the completion or commercial development of these projects could materially reduce our liquidity 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 to 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, 2011, we had $2.1 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 operating surplus 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. These cash reserves will affect the amount of cash available for distribution to our unitholders and our ability to pay cash distributions could be materially reduced by our general partner's board of directors.

Cyber attacks that circumvent our security measures could disrupt our operations.

We operate our pipeline and terminals 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. We may not have the resources or technical sophistication to anticipate or prevent every emerging type of cyber attack, and 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, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (“IRS”) were to treat us as a corporation for federal income tax purposes or if we become subject to a material amount of entity-level taxation for state tax purposes, 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, at the federal level, members of the U.S. Congress have recently considered substantive changes to the existing federal income tax laws that would have affected certain publicly traded partnerships. Although the most recently proposed legislation would not appear to affect us, such legislation could be reintroduced and amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes, or other proposals, will be reintroduced or 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. Specifically, 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 and our general partner 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. In 2009, the Department of the Treasury and the IRS 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.

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. 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 twelve-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 twelve-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 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 twelve months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. Our technical termination would not affect our classification as a partnership for federal income tax purposes.

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 22 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. It is our unitholders' responsibility to file all U.S. federal, state and local tax returns.

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 February 2012, we received two Notices of Enforcement from the Texas Commission on Environmental Quality related to unauthorized emissions that occurred as a result of an excess buildup of water on the top of floating roof tanks. We have accrued an amount for potential monetary sanctions related to this matter of approximately $0.1 million. 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 July 2011, we received an information request from the EPA, pursuant to Section 308 of the Water Pollution Control Act, regarding a pipeline release in February 2011 near Texas City, Texas. We have accrued an amount for potential monetary sanctions related to this matter of approximately $0.1 million. 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. In the opinion of management, the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements is not expected to have a material adverse effect on our 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 (“NYSE”) under the ticker symbol “MMP.” At the close of business on February 1, 2012, we had 113,100,436 limited partner units outstanding that were owned by approximately 112,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $56.50 on December 31, 2010 and $68.88 on December 30, 2011. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2010 and 2011 were as follows:

	2010			2011		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$47.65	$39.81	$0.7200	$60.57	$53.33	$0.7700
2nd	$48.60	$39.85	$0.7325	$63.10	$55.55	$0.7850
3rd	$51.47	$45.55	$0.7450	$61.85	$51.00	$0.8000
4th	$57.43	$51.45	$0.7575	$69.21	$57.38	$0.8150

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

We must distribute all of our available cash, as defined in our partnership agreement, at the end of each quarter, less reserves established by our general partner. We currently pay quarterly cash distributions of $0.815 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 29, 2006 and that all distributions or dividends were reinvested on a quarterly basis.

	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/30/2011
Magellan Midstream Partners, L.P.	$100.00	$118.87	$89.15	$138.22	$191.45	$245.70
Alerian MLP Index	$100.00	$112.72	$71.11	$125.45	$170.42	$194.07
S&P 500	$100.00	$105.48	$66.52	$84.07	$96.71	$98.76

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.

We present the financial measure of distributable cash flow ("DCF"), which is not a generally accepted accounting principles ("GAAP") measure, in the following tables. 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 distributable cash flow 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 measure of operating margin (in the aggregate and by segment) is presented in the following tables. We compute the components of operating margin 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. 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.

	Year Ended December 31,				
	2007	2008	2009	2010	2011
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$608,781	$638,810	$678,945	$793,599	$893,369
Product sales revenues	709,564	574,095	334,465	763,090	854,528
Affiliate management fee revenues	712	733	761	758	770
Total revenues	1,319,057	1,213,638	1,014,171	1,557,447	1,748,667
Operating expenses	250,935	264,871	257,635	282,212	306,415
Product purchases	633,909	436,567	280,291	668,585	706,270
Gain on assignment of supply agreement	—	(26,492)	—	—	—
Equity earnings	(4,027)	(4,067)	(3,431)	(5,732)	(6,763)
Operating margin	438,240	542,759	479,676	612,382	742,745
Depreciation and amortization expense	79,140	86,501	97,216	108,668	121,179
G&A expense	74,859	73,302	84,049	95,316	98,669
Operating profit	284,241	382,956	298,411	408,398	522,897
Interest expense, net	47,653	50,479	69,187	93,296	105,634
Debt prepayment premium	1,984	—	—	—	—
Debt placement fee amortization	1,554	767	1,112	1,401	1,831
Other (income) expense, net	728	(380)	(24)	750	—
Income before provision for income taxes	232,322	332,090	228,136	312,951	415,432
Provision for income taxes	1,568	1,987	1,661	1,371	1,866
Net income	$230,754	$330,103	$226,475	$311,580	$413,566
Net income allocation:[(a)]					
Non-controlling owners' interest	$175,356	$244,430	$99,729	$(397)	$(63)
Limited partner interests	61,580	87,733	126,746	311,977	413,629
General partner interest	(6,182)	(2,060)	—	—	—
Net income	$230,754	$330,103	$226,475	$311,580	$413,566
Basic net income per limited partner unit	$1.55	$2.21	$2.22	$2.85	$3.67
Diluted net income per limited partner unit	$1.55	$2.21	$2.22	$2.85	$3.66
Balance Sheet Data:					
Working capital (deficit)[(b)]	$(15,609)	$(29,644)	$94,571	$109,536	$301,135
Total assets	$2,416,931	$2,600,708	$3,163,148	$3,717,900	$4,045,001
Long-term debt	$914,536	$1,083,485	$1,680,004	$1,906,148	$2,151,775
Owners' equity	$1,184,566	$1,254,132	$1,196,354	$1,469,571	$1,463,403
Cash Distribution Data:					
Cash distributions declared per MMP unit[(c)]	$2.55	$2.77	$2.84	$2.96	$3.17
Cash distributions paid per MMP unit[(c)]	$2.49	$2.72	$2.84	$2.91	$3.11

	Year Ended December 31,				
	2007	2008	2009	2010	2011
	(in thousands, except per unit amounts and operating statistics)				
Other Data:					
Operating margin (loss):					
Petroleum pipeline system	$354,914	$428,903	$361,598	$480,781	$572,198
Petroleum terminals	83,289	101,713	110,573	132,748	160,350
Ammonia pipeline system	(2,995)	8,660	3,666	(4,156)	7,279
Allocated partnership depreciation costs[d]	3,032	3,483	3,839	3,009	2,918
Operating margin	$438,240	$542,759	$479,676	$612,382	$742,745
Distributable cash flow:					
Net income	$230,754	$330,103	$226,475	$311,580	$413,566
Depreciation and amortization expense[e]	80,694	87,268	98,328	110,069	123,010
Equity-based incentive compensation expense[f]	6,213	931	6,123	15,499	10,243
Asset retirements and impairments	8,548	7,180	5,529	1,062	8,599
Commodity-related adjustments:					
NYMEX losses (gains) recognized in the period associated with products that will be sold in future periods[g]	—	(20,200)	10,475	14,945	(5,909)
NYMEX losses (gains) recognized in previous periods associated with products that were sold in the period[h]	—	—	20,200	(7,675)	(15,162)
Lower-of-cost-or-market adjustments	—	6,413	(6,413)	3	1,017
Houston-to-El Paso cost of sales adjustment[i]	—	—	—	478	(2,316)
Maintenance capital	(31,243)	(43,232)	(37,999)	(44,620)	(70,002)
Expenses paid by (credited to) a former affiliate[j]	10,617	(4,344)	5,144	—	—
Product supply agreement gains[k]	(2,563)	(26,919)	—	—	—
Other[l]	(4,876)	1,013	541	(1,582)	(2,504)
Distributable cash flow	$298,144	$338,213	$328,403	$399,759	$460,542
Operating Statistics:					
Petroleum pipeline system:					
Transportation revenue per barrel shipped	$1.147	$1.193	$1.205	$1.160	$1.082
Volume shipped (million barrels):[m]					
Refined products:					
Gasoline	159.8	152.7	169.9	194.3	208.9
Distillates	119.6	114.8	100.2	122.9	136.0
Aviation fuel	24.6	22.2	19.8	22.6	25.3
Liquefied petroleum gases	3.2	6.2	5.8	5.0	4.9
Crude oil	—	—	—	14.7	43.2
Total volume shipped	307.2	295.9	295.7	359.5	418.3
Petroleum terminals:					
Storage terminal average utilization (million barrels per month)	19.9	21.4	23.5	25.8	32.1
Inland terminal throughput (million barrels)	117.3	108.1	109.8	114.7	115.6
Ammonia pipeline system:					
Volume shipped (thousand tons)	716	822	643	462	727

(a) Prior to September 28, 2009, the date the simplification of our capital structure closed (see Note 2–Summary of Significant Accounting Policies in the accompanying notes to consolidated financial statements for a discussion of the simplification), net income allocations were as follows:

- Non-controlling owners' interest was our net income allocated to owners other than Magellan Midstream Holdings, L.P. ("Holdings"), the owner of our general partner at that time;
- Limited partner interests was net income allocated to Holdings' limited partner unitholders; and
- General partner interest was the net loss allocated to Holdings' general partner.

Following the simplification, the non-controlling owners' interest was eliminated and 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) Our working capital at December 31, 2011 was significantly higher than previous years because we had $209.6 million of cash and cash equivalents on hand.

(c) 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.

(d) 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.

(e) Includes debt placement fee amortization.

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

(g) Certain derivatives we use as economic hedges do not qualify for hedge accounting treatment. We recognize the change in fair value of these agreements each accounting period in our earnings, even if the hedged product has not yet been physically sold. These amounts represent the gains or losses of hedged products recognized in our earnings for products that we have not yet physically sold.

(h) When we physically sell products that we have economically hedged, we include in our DCF calculations the full amount of the change in fair value of the associated derivative agreement.

(i) Cost of goods sold adjustment related to transitional commodity activities for our Houston-to-El Paso pipeline to more closely resemble current market prices for DCF purposes rather than average inventory costing as used to determine our results of operations.

(j) In periods prior to the completion of our simplification in September 2009, we had agreements with our general partner and its affiliates that provided reimbursement for (i) certain G&A costs above specified amounts and (ii) certain environmental costs that were subject to an environmental indemnification settlement in 2004. In addition, our G&A costs included non-cash expenses to us for a payment made by our general partner's affiliate to one of our executive officers. In 2008, we negotiated a settlement with the EPA for environmental matters that were part of the 2004 indemnification settlement. The settlement was for an amount less than had been previously accrued for these matters, which consequently reduced expenses and increased net income.

(k) 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.

(l) Other primarily includes adjustments for equity investment earnings and distributions and non-controlling owners' interests losses included in net income during 2010 and 2011.

(m) Excludes capacity leases.

32

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

Introduction

We are a publicly traded limited partnership formed to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the transportation, storage and distribution of petroleum products, such as gasoline, diesel fuel and crude oil. As of December 31, 2011, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 50 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.

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, 2011.

Recent Developments

Debt Offering. In August 2011, we issued an additional $250.0 million of our 4.25% notes due 2021. We sold these notes at a price of 104.1% of their face value, or $260.2 million. Net proceeds from this offering, including accrued interest of $0.7 million, were $258.7 million after underwriting discounts of $1.6 million and other offering costs of $0.6 million. Proceeds from this debt offering were used to repay all of the borrowings outstanding under our revolving credit facility, which totaled $193.0 million at the time, and for general partnership purposes, including investments in capital expenditures.

Pipeline Conversion to Crude Service. In September 2011, we announced that we are proceeding with the reversal and conversion of a large portion of our Houston-to-El Paso pipeline to crude oil service. The reversed pipeline system, which will transport crude oil from Crane, Texas to refiners or third-party pipelines in Houston and Texas City, Texas, is expected to have an initial capacity of approximately 135,000 barrels per day. We have received long-term committed volumes for a portion of this capacity. The tariffs we expect to charge on crude oil movements on this pipeline after the reversal will be between $1.38 and $2.30 per barrel, depending upon volumes committed and ultimate destination. This project is expected to cost approximately $245.0 million, which we expect to finance through the cash and cash equivalents we have on hand and borrowings from our revolving credit facility. Subject to receiving the necessary permits and regulatory approvals, we expect the reversed pipeline to be operational by early 2013. We expect this project will have a materially favorable impact on our results of operations beginning in 2013.

Prior to the completion of this pipeline reversal project, we expect to discontinue substantially all of the pipeline linefill activities that we currently conduct in connection with our operation of the Houston-to-El Paso pipeline and we expect to sell substantially all of the associated linefill inventory which, at December 31, 2011, was 0.7 million barrels of refined petroleum products with a carrying value of approximately $79.7 million.

We will be able to shift the volumes of refined products we are currently transporting 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.

New Revolving Credit Facility. In October 2011, we terminated our existing revolving credit facility that would have matured in September 2012 and entered into a new revolving credit facility. The new facility has total borrowing capacity of $800 million and matures in October 2016. Borrowings under the new facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding. Additionally, a commitment fee is assessed on undrawn amounts at a rate between 0.125% and 0.30%, depending on our credit ratings, which was 0.2% at December 31, 2011.

MF Global Holdings Ltd. Bankruptcy. 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 ("SIPA"). At that time, MF Global served as our sole clearing agent for New York Mercantile Exchange ("NYMEX") futures contracts.

The Chicago Mercantile Exchange ("CME") requires us to maintain adequate margin against our NYMEX positions, which our clearing agent is required to hold on our behalf in a segregated account. In October 2011, MF Global disclosed to the CME that it had a "significant shortfall" in its segregated customer accounts. We transferred our existing trading positions at MF Global to a new clearing agent on November 4, 2011, and all of our NYMEX activity is now being conducted with our new clearing agent.

As of November 4, 2011, the date of transfer of our account, MF Global owed us $29.4 million; however, we have subsequently received $21.2 million as partial payment on our account. We have submitted a claim with the trustee for the SIPA liquidation of MF Global for $8.2 million, which represents the remaining amount owed to us by MF Global. At this point it is uncertain what additional funds MF Global will have available for distribution to its former customers as well as how the claims against MF Global's remaining assets may be prioritized. As of December 31, 2011, we have not reserved any of the receivable balance owed to us by MF Global.

Double Eagle Pipeline LLC. In December 2011, we formed a joint venture with Copano Energy, L.L.C. ("Copano") to deliver Eagle Ford shale condensate to Corpus Christi, Texas. We have a 50% interest in this joint venture, known as Double Eagle Pipeline LLC ("Double Eagle"), with Copano owning 50%. We are accounting for our investment in Double Eagle as an equity investment. Double Eagle will construct and own approximately 140 miles of pipeline to connect an existing 50-mile pipeline segment owned by Copano, enabling delivery of approximately 100,000 barrels per day of condensate from the Eagle Ford shale formation to our terminal in Corpus Christi. Copano will oversee the construction of the pipeline and will serve as operator once pipeline operations commence. This project is supported by long-term customer commitments and is expected to be operational in early 2013. In conjunction with this project (but separate from the joint venture with Copano), we are making enhancements to our Corpus Christi terminal, including the construction of 500,000 barrels of dedicated condensate storage and a dedicated dock delivery pipeline. This project will cost approximately $100.0 million, which includes $75.0 million for our portion of the pipeline construction and $25.0 million for tankage and other infrastructure changes at our Corpus Christi terminal.

Retention of Ammonia Pipeline. During 2011, we evaluated the potential sale of our ammonia pipeline system. After reviewing potential alternatives, we have decided to retain this asset at this time.

Cash Distribution. In January 2012, the board of directors of our general partner declared a quarterly cash distribution of $0.815 per unit for the period of October 1, 2011 through December 31, 2011. This quarterly cash distribution was paid on February 14, 2012 to unitholders of record on February 7, 2012. The total distributions paid on 113.1 million limited partner units outstanding was $92.2 million.

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 13 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 more than 44% of the refinery capacity in the continental U.S. In 2011, the petroleum pipeline system generated 72% of its revenues, excluding the sale of petroleum products, 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.

Most 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. Further, we own and have title to a portion of the linefill of the Houston-to-El Paso pipeline section, and we take title to the petroleum products we transport on this pipeline for sale in El Paso, Texas. 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 a significant portion of our Houston-to-El Paso pipeline segment 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 $549.8 million on acquisitions and growth projects during 2011 and 2010, respectively. Further, we currently expect to spend approximately $430.0 million in 2012 on projects now underway, with additional spending of approximately $90.0 million in 2013 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 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 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, 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	(17.8)	(24)%
Ammonia pipeline system	19.1	16.4	2.7	14%
Intersegment eliminations	(3.1)	(2.9)	(0.2)	(6)%
Total operating expenses	282.2	306.4	(24.2)	(9)%
Product margin:				
Product sales	763.1	854.5	91.4	12%
Product purchases	668.6	706.3	(37.7)	(6)%
Product margin [(a)]	94.5	148.2	53.7	57%
Equity earnings	5.7	6.8	1.1	19%
Operating margin	612.4	742.8	130.4	21%
Depreciation and amortization expense	108.7	121.2	(12.5)	(11)%
G&A expense	95.3	98.7	(3.4)	(4)%
Operating profit	408.4	522.9	114.5	28%
Interest expense (net of interest income and interest capitalized)	93.3	105.6	(12.3)	(13)%
Debt placement fee amortization	1.4	1.8	(0.4)	(29)%
Other expense	0.7	—	0.7	n/a
Income before provision for income taxes	313.0	415.5	102.5	33%
Provision for income taxes	1.4	1.9	(0.5)	(36)%
Net income	$311.6	$413.6	$102.0	33%
Operating Statistics				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.160	$1.082		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	194.3	208.9		
Distillates	122.9	136.0		
Aviation fuel	22.6	25.3		
Liquefied petroleum gases	5.0	4.9		
Crude oil	14.7	43.2		
Total volume shipped	359.5	418.3		
Petroleum terminals:				

Storage terminal average utilization (million barrels per month)	25.8	32.1
Inland terminal throughput (million barrels)	114.7	115.6
Ammonia pipeline system:		
Volume shipped (thousand tons)	462	727

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

Transportation and terminals revenues increased by $99.8 million, resulting from:

- an increase in petroleum pipeline system revenues of $53.8 million. Revenues from the pipelines we acquired from BP Pipelines (North America), Inc. ("BP") in September 2010 contributed $16.8 million of this increase. Otherwise, revenues increased $37.0 million primarily attributable to:

a 4% increase in the average per-barrel tariff rate, going from $1.276 to $1.321, principally reflecting the 7% tariff rate increase we implemented on July 1, 2011;

a 2% increase in transportation volumes driven primarily by higher demand for diesel fuel; and

higher lease storage revenue primarily due to new tanks added to our system during 2010 and 2011, higher capacity lease revenues due to increased demand and increased fees for terminal throughput, ethanol and other blending services;

- an increase in petroleum terminals revenues of $38.3 million, of which approximately 40% was contributed by the increase in revenues from our Cushing, Oklahoma storage assets acquired in September 2010. Otherwise, storage terminal revenues increased principally due to leases of newly constructed tanks at Cushing, Oklahoma and Galena Park, Texas that were placed in service over the last year. In addition, inland revenues increased primarily from higher ethanol and additive fees; and

- an increase in ammonia pipeline system revenues of $8.7 million. Hydrostatic testing performed on the ammonia pipeline during 2010 rendered the pipeline unavailable for shipments for much of that year, which resulted in lower revenues.

Operating expenses increased $24.2 million, resulting from:

- an increase in petroleum pipeline system expenses of $8.9 million. Pipeline system expenses decreased $7.5 million related to our September 2010 pipeline purchase because favorable product overages (which reduce operating expenses) more than offset other operating expenses related to these acquired assets. Otherwise, petroleum pipeline expenses increased $16.4 million due to higher property taxes, increased losses from asset replacements and impairments, expenses recognized in the current period related to potential air emission fees for our Houston-area terminals, higher power costs due to increased pipeline volumes and higher compensation costs;

- an increase in petroleum terminals expenses of $17.8 million, of which $5.5 million was attributable to the increase in expenses for the Cushing storage assets acquired in September 2010. Excluding these costs, operating expenses increased $12.3 million primarily related to expenses recognized in the current period for potential air emission fees at our Galena Park, Texas facility, incremental costs related to product contamination issues and higher compensation costs; and

- a decrease in ammonia pipeline system expenses of $2.7 million due primarily to higher asset integrity costs in 2010 from the hydrostatic testing performed on our pipeline during that year.

Product sales revenues primarily result from our petroleum products blending activities, product marketing and linefill management associated with our Houston-to-El Paso pipeline section, terminal product gains and transmix fractionation. We utilize NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in the future related to these activities. The period change in the mark-to-market value of these contracts that do not qualify for hedge accounting treatment, 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 swap 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 swap agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin increased $53.7 million between periods due primarily to favorable unrealized gains from NYMEX contracts as a result of the timing of those agreements, and increased profits from our petroleum products blending and fractionation activities. The increase in our petroleum products blending profits was primarily attributable to higher average product prices, and the increase in fractionation profits was due to an increase in fractionation volumes and higher product prices.

Equity earnings increased $1.1 million due primarily to increased shipments on a crude oil pipeline in which we own a

50% interest.
Depreciation and amortization expense increased $12.5 million primarily due to expansion capital projects placed into service during 2011 and recent acquisitions.

G&A expense increased $3.4 million between periods primarily due to higher compensation costs in 2011 related in large part to our crude oil development operations and higher costs related to financial system upgrades.
Interest expense, net of interest income and interest capitalized, increased $12.3 million in 2011. Our average debt outstanding increased to $2.1 billion in 2011 from $1.8 billion in 2010 principally due to borrowings for expansion capital expenditures and recent acquisitions. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, was 5.4% and 5.3%, respectively, for 2010 and 2011.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2010

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2009	2010	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$494.2	$584.0	$89.8	18%
Petroleum terminals	167.0	196.7	29.7	18%
Ammonia pipeline system	19.9	14.9	(5.0)	(25)%
Intersegment eliminations	(2.2)	(2.0)	0.2	9%
Total transportation and terminals revenues	678.9	793.6	114.7	17%
Affiliate management fee revenues	0.8	0.8	—	—%
Operating expenses:				
Petroleum pipeline system	181.0	191.0	(10.0)	(6)%
Petroleum terminals	64.3	75.2	(10.9)	(17)%
Ammonia pipeline system	16.2	19.1	(2.9)	(18)%
Intersegment eliminations	(3.9)	(3.1)	(0.8)	(21)%
Total operating expenses	257.6	282.2	(24.6)	(10)%
Product margin:				
Product sales	334.5	763.1	428.6	128%
Product purchases	280.3	668.6	(388.3)	(139)%
Product margin [(a)]	54.2	94.5	40.3	74%
Equity earnings	3.4	5.7	2.3	68%
Operating margin	479.7	612.4	132.7	28%
Depreciation and amortization expense	97.2	108.7	(11.5)	(12)%
G&A expense	84.1	95.3	(11.2)	(13)%
Operating profit	298.4	408.4	110.0	37%
Interest expense (net of interest income and interest capitalized)	69.2	93.3	(24.1)	(35)%
Debt placement fee amortization	1.1	1.4	(0.3)	(27)%
Other (income) expense	(0.1)	0.7	(0.8)	n/a
Income before provision for income taxes	228.2	313.0	84.8	37%
Provision for income taxes	1.7	1.4	0.3	18%
Net income	$226.5	$311.6	$85.1	38%
Operating Statistics				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.205	$1.160		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	169.9	194.3		
Distillates	100.2	122.9		
Aviation fuel	19.8	22.6		
Liquefied petroleum gases	5.8	5.0		
Crude oil	—	14.7		
Total volume shipped	295.7	359.5		

Petroleum terminals:		
Storage terminal average utilization (million barrels per month)	23.5	25.8
Inland terminal throughput (million barrels)	109.8	114.7
Ammonia pipeline system:		
Volume shipped (thousand tons)	643	462

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

Transportation and terminals revenues increased by $114.7 million, resulting from:

- an increase in petroleum pipeline system revenues of $89.8 million primarily attributable to higher transportation revenues, higher pipeline capacity and storage lease revenues and incremental fees for terminal throughput, ethanol blending and additives. Transportation revenues increased primarily as a result of higher diesel fuel volumes driven by improved economic conditions and additional volumes from acquisitions completed during 2010 and growth projects, as well as higher tariff rates due to the mid-2009 tariff escalation. Overall transportation revenue per barrel shipped declined between periods because the tariffs related to the Texas pipelines acquired from BP in September 2010 were significantly lower than our remaining pipeline system due to the short distance of the pipeline movements between Houston and Texas City, Texas. Excluding the recently-acquired pipelines, transportation rates increased for the remainder of our pipeline system by $0.07 per barrel, or 6%, primarily due to longer haul shipments;

- an increase in petroleum terminals revenues of $29.7 million due to higher revenues at both our storage and inland terminals. Storage terminal revenues increased principally due to higher rates on existing storage, leasing new storage tanks placed in service over the past year and the acquisition of storage in Cushing, Oklahoma. Inland revenues benefited from higher fees due to ethanol blending and increased throughput volumes; and

- a decrease in ammonia pipeline system revenues of $5.0 million due to lower shipments resulting from the hydrostatic testing performed on our pipeline which rendered the pipeline unavailable for shipments for much of 2010.

Operating expenses increased by $24.6 million, resulting from:

- an increase in petroleum pipeline system expenses of $10.0 million due primarily to higher operating expenses related to our Houston-to-El Paso pipeline section (which we acquired in third quarter 2009) and higher power costs resulting from increased shipments;

- an increase in petroleum terminals expenses of $10.9 million primarily related to higher asset maintenance, environmental and personnel costs; and

- an increase in ammonia pipeline system expenses of $2.9 million due primarily to an increase in asset integrity costs from the hydrostatic testing performed on our pipeline during 2010.

Product sales revenues primarily resulted from our petroleum products blending activities, product marketing and linefill management associated with our Houston-to-El Paso pipeline section, terminal product gains and transmix fractionation. We utilize NYMEX contracts to hedge against changes in the future price of petroleum products related to these activities. The period change in the mark-to-market value of these contracts that do not qualify for hedge accounting treatment plus the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment are also included in product sales revenues. Product margin increased $40.3 million primarily due to the timing of the recognition of gains and losses from our NYMEX contracts. Due to mark-to-market adjustments on NYMEX contracts, much of the profit related to the commodity sales activity during the 2009 period was recognized in late 2008. Product margin also increased in the current year due to higher profits from our petroleum products blending and fractionation activities as well as profits from our linefill management activities associated with our Houston-to-El Paso pipeline section, and the sale of terminal product overages at higher prices.
Equity earnings increased $2.3 million due primarily to increased shipments on a crude oil pipeline in which we own a 50% interest.
Depreciation and amortization expense increased by $11.5 million primarily due to expansion capital projects and acquisitions in 2009 and 2010.

G&A expense increased by $11.2 million between periods primarily due to higher equity-based incentive compensation costs, resulting from actual results significantly exceeding the financial performance goals established by the compensation committee of our general partner's board of directors.

Interest expense, net of interest income and interest capitalized, increased $24.1 million in 2010. Our average debt outstanding increased to $1.8 billion for 2010 from $1.4 billion for 2009 principally due to borrowings for expansion capital expenditures and acquisitions during 2010. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, was 5.4% for both 2009 and 2010.

Distributable Cash Flow

Distributable cash flow is a non-GAAP measure that management uses to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this measure as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. We believe that investors benefit from having access to the same financial measures utilized by management for these evaluations. A reconciliation of distributable cash flow for the years ended December 31, 2009, 2010 and 2011 to net income, which is its nearest comparable GAAP financial measure, was as follows (in thousands):

	Year Ended December 31,		
	2009	2010	2011
Net income	$226,475	$311,580	$413,566
Depreciation and amortization[1]	98,328	110,069	123,010
Equity-based incentive compensation expense[2]	6,123	15,499	10,243
Asset retirements and impairments	5,529	1,062	8,599
Expenses paid by a former affiliate[3]	5,144	—	—
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with products that will be sold in future periods[4]	10,475	14,945	(5,909)
Derivative losses (gains) recognized in previous periods associated with products sold in the period[5]	20,200	(7,675)	(15,162)
Lower-of-cost-or-market adjustments	(6,413)	3	1,017
Houston-to-El Paso cost of sales adjustments[6]	—	478	(2,316)
Total commodity-related adjustments	24,262	7,751	(22,370)
Maintenance capital	(37,999)	(44,620)	(70,002)
Other	541	(1,582)	(2,504)
Distributable cash flow	$328,403	$399,759	$460,542

(1) Depreciation and amortization includes debt placement fee amortization.

(2) Because the partnership intends to satisfy vesting of units under its equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for distributable cash flow purposes. Total equity-based incentive compensation expense for the years ended December 31, 2009, 2010 and 2011 was $9.6 million, $18.9 million and $17.6 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings paid by the partnership in 2009, 2010 and 2011 of $3.5 million, $3.4 million and $7.4 million, respectively, for equity-based incentive compensation units that vested on the previous year end, which reduce distributable cash flow.

(3) In periods prior to September 2009, we had an agreement with our general partner and its affiliates that provided reimbursement for certain environmental costs that were subject to an environmental indemnification settlement in 2004.

(4) Derivatives we use as economic hedges that have not been designated as hedges for accounting purposes. These amounts represent the gains or losses from these economic hedges recognized in our earnings for products that had not physically sold as of the period end date.

(5) When we physically sell products that are economically hedged (but were not designated as hedges for accounting purposes), we include in our distributable cash flow calculations the full amount of the change in fair value of the associated derivative agreement.

(6)

Cost of goods sold adjustment related to commodity activities for our Houston-to-El Paso pipeline to more closely resemble current market prices for distributable cash flow purposes rather than average inventory costing as used to determine our results of operations.

Distributable cash flow increased $71.4 million between 2009 and 2010 and increased $60.8 million between 2010 and 2011. The change in net income and depreciation and amortization between periods is discussed in detail in Results of Operations above, the change in equity-based compensation is discussed in footnote [(2)] above and a discussion of our maintenance capital expenditures is provided in Capital Requirements below. A discussion of the other components of DCF are as follows:

- Adjustments for asset retirements and impairments were lower in the 2010 period because of a $3.0 million insurance settlement, which we excluded from our distributable cash flow calculations. The amounts for 2011 include an impairment expense of $2.8 million; and

41

- The changes in distributable cash flows from commodity-related adjustments is primarily due to the impact of product price changes during each period on economic hedges that do not qualify for hedge accounting treatment.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $269.4 million, $424.7 million and $577.3 million for the years ended December 31, 2009, 2010 and 2011, respectively.

- The $152.6 million increase from 2010 to 2011 was primarily attributable to:

a $113.3 million increase in net income, excluding the increase in non-cash depreciation and amortization expense and equity-based incentive compensation expense;
a $28.8 million increase resulting from a $14.4 million increase in cash due to the elimination of restricted cash due to our purchase of a private group's investment in a Cushing, Oklahoma storage project ("MCO") during 2011 versus a decrease in cash of the same amount associated with the formation of MCO during 2010. MCO's cash on hand was unavailable to us for our partnership matters and was recorded as restricted cash on our consolidated balance sheet at December 31, 2010;
a $23.0 million increase resulting from a $5.8 million decrease in trade accounts receivable and other accounts receivable in 2011 versus a $17.2 million increase in trade accounts receivable and other accounts receivable in 2010. The increase during 2010 was primarily due to the acquisition of certain storage and pipeline assets from BP and timing of payments from our customers;
an $18.9 million increase resulting from a $16.9 million increase in current and noncurrent environmental liabilities in 2011 versus a $2.0 million decrease in current and noncurrent environmental liabilities. The increase during 2011 was primarily due to accruals related to potential air emission fees and current year and historical product releases; and
a $12.4 million increase resulting from a $20.2 million increase in accounts payable in 2011 versus a $7.8 million increase in accounts payable in 2010 primarily due to the timing of invoices paid to vendors and suppliers.
These increases were partially offset by:
a $23.5 million decrease resulting from a $19.8 million decrease in energy commodity derivatives contracts, net of derivatives deposits, in 2011 versus a $3.7 million increase in energy commodity derivatives contracts, net of derivatives deposits, in 2010 due to the change in commodity prices during the respective periods; and
a $19.1 million decrease primarily resulting from the impact of higher product prices and higher levels of inventory purchases in 2011 as compared to 2010; specifically, a $42.5 million increase in inventory in 2011 versus a $23.4 million increase in inventory in 2010.

- The $155.3 million increase from 2009 to 2010 was primarily attributable to:

a $105.8 million increase in net income, excluding the increase in non-cash depreciation and amortization expense and equity-based incentive compensation expense;
a $35.7 million increase resulting from lower levels of inventory purchases in 2010 as compared to 2009; specifically, a $23.4 million increase in inventory in 2010 versus a $59.1 million increase in inventory in 2009 primarily due to the purchase of Houston-to-El Paso linefill inventory during 2009;
a $14.7 million increase resulting from a $17.2 million increase in trade accounts receivable and other accounts receivable in 2010 versus a $31.9 million increase in trade accounts receivable and other accounts receivable in 2009. The increase during 2010 is primarily due to the acquisition of certain storage and pipeline assets from BP and timing of payments from our customers. The increase during 2009 is primarily due to an increase in product prices during late 2009 and timing of payments from our customers;

an $11.9 million increase resulting from a $3.7 million increase in energy commodity derivatives contracts liability, net of derivatives deposits in 2010 primarily due to additional NYMEX commodity contracts associated with the crude oil working inventory we acquired as part of our acquisition from BP versus an $8.2 million decrease in energy commodity derivatives contracts liability, net of derivatives deposits in 2009 primarily due to the increase in outstanding NYMEX commodity contracts during 2009, most of which was due to our purchase of the Houston-to-El Paso linefill inventory; and

an $11.7 million increase resulting from a $7.8 million increase in accounts payable in 2010 versus a $3.9 million decrease in accounts payable in 2009 primarily due to the timing of invoices paid to vendors and suppliers.

These increases were partially offset by:

a $14.9 million decrease resulting from a $2.9 million increase in accrued interest payable in 2010 versus a $17.8 million increase in accrued interest payable in 2009 due primarily to the timing of semi-annual interest payments; and

a $14.4 million decrease resulting from cash restricted in 2010 due to the formation of MCO, a consolidated entity. MCO's cash on hand was unavailable to us for our partnership matters and was recorded as restricted cash on our consolidated balance sheet at December 31, 2010.

Net cash used by investing activities for the years ended December 31, 2009, 2010 and 2011 was $604.9 million, $590.2 million and $258.7 million, respectively. During 2011, we spent $199.7 million for capital expenditures, which included $70.0 million for maintenance capital and $129.7 million for expansion capital. Also during 2011, we acquired a private investment group's common equity in MCO for $40.5 million, spent $17.8 million on various asset acquisitions and invested $10.7 million in joint ventures we account for as equity investments. During 2010, we acquired storage and pipeline assets for $291.3 million and tank bottom inventories for $53.0 million from BP. Also during 2010, we acquired petroleum products storage tanks at various locations on our petroleum pipeline system for $29.3 million, and we spent $221.4 million for capital expenditures, which included $45.2 million for maintenance capital and $176.2 million for expansion capital. During 2009, we acquired the Houston-to-El Paso pipeline section for $252.3 million plus the fair market value of the associated linefill of $86.1 million. We also acquired a petroleum products terminal in Oklahoma for $20.0 million and a facility adjacent to one of our existing storage terminals in Louisiana for $32.2 million plus related liabilities assumed of $2.2 million. Additionally, capital expenditures in 2009 were $216.7 million, which included $43.3 million for maintenance capital and $173.4 million for expansion capital.

Net cash provided (used) by financing activities for the years ended December 31, 2009, 2010 and 2011 was $301.7 million, $168.8 million and $(116.4) million, respectively. During 2011, we received net proceeds of $260.9 million from borrowings under notes, which were used to repay the outstanding balance on our revolving credit facility of $193.0 million at that time, with the balance used for general partnership purposes. Additionally, we paid cash distributions of $350.9 million to our unitholders while borrowings on our revolving credit facility of $178.0 million, prior to being repaid, were primarily used to finance expansion capital projects and acquisitions. During 2010, we received net proceeds of $258.4 million from our public offering of limited partner units and $298.9 million, net of discounts, from borrowings under notes. Combined, these net proceeds were used primarily to acquire certain assets from BP and to repay outstanding borrowings on our revolving credit facility of $175.5 million at that time, with the balance used for general partnership purposes. Additionally, we paid cash distributions of $318.8 million to our unitholders while net repayments on our revolving credit facility, including the $175.5 million repayment above, were $86.6 million. Also during 2010, we received proceeds of $16.2 million from the termination and settlement of interest rate swap agreements. During 2009, proceeds from note issuances (including net premium) of $568.7 million were used to repay, in total, $454.3 million of borrowings on our revolving credit facility, with the balance used for general partnership purposes, including capital expenditures. Borrowings on the revolver during 2009, net of repayments, were $31.6 million. Additionally, cash distributions of $285.8 million were paid to unitholders during 2009.

The quarterly distribution amount related to fourth quarter 2011 was $0.815 per unit, which was paid in February 2012. If we are able to meet management's targeted distribution growth of 9% during 2012 and the number of outstanding limited partner units remains at 113.1 million, total cash distributions of approximately $390.8 million will be paid to our unitholders related to 2012.

In January 2011, the cumulative amounts of the January 2008 equity-based incentive compensation award grants were settled by issuing 252,746 limited partner units and distributing those units to the participants. Associated tax withholdings of $7.4 million and employer taxes of $0.9 million were paid in January 2011.

Capital Requirements

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

- maintenance capital expenditures, such as those required to maintain equipment reliability and safety and to address environmental regulations; and

- expansion capital expenditures to acquire additional complementary assets to grow our business and to expand or upgrade our existing facilities, which we refer to as organic growth projects. Organic growth projects include capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During 2010 and 2011, our maintenance capital spending was $45.2 million, including $0.6 million of spending reimbursable by insurance, and $70.0 million, respectively. The $24.8 million increase was primarily attributable to an increase in the amount of regulatory and integrity work performed on our pipeline and terminals systems, maintenance capital for recently-acquired assets and the relocation of river crossings along our Houston-to-El Paso pipeline section and ammonia pipeline system. For 2012, we also expect to incur maintenance capital expenditures for our existing businesses of approximately $70.0 million.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities and acquire new assets. Expenditures for organic growth projects and acquisitions during 2011 were $198.9 million. Based on the progress of expansion projects already underway, we expect to spend approximately $430.0 million of expansion capital during 2012 with an additional $90.0 million in 2013 to complete these projects.

Liquidity

Cash generated from operations is our primary source of liquidity for funding debt service, maintenance capital expenditures and quarterly distributions. Additional liquidity for purposes other than quarterly distributions, such as capital expenditures and debt repayments, is available through borrowings under our revolving credit facility discussed below, as well as from other borrowings or issuances of debt or limited partner units. If capital markets do not permit us to issue additional debt and equity, our business may be adversely affected, and we may not be able to acquire additional assets and businesses, fund organic growth projects or repay our debts when they become due.

Debt at December 31, 2010 and 2011 was as follows (in thousands):

	December 31, 2010	December 31, 2011	Weighted-Average Interest Rate at December 31, 2011 (a)
Revolving credit facility	$15,000	$—	—%
$250.0 million of 6.45% Notes due 2014	249,786	249,844	6.3%
$250.0 million of 5.65% Notes due 2016	252,466	252,037	5.6%
$250.0 million of 6.40% Notes due 2018	259,125	263,477	5.0%
$550.0 million of 6.55% Notes due 2019	581,890	578,521	5.6%
$550.0 million of 4.25% Notes due 2021	298,932	558,932	4.1%
$250.0 million of 6.40% Notes due 2037	248,949	248,964	6.4%
Total debt	$1,906,148	$2,151,775	5.3%

(a) Weighted-average interest rate includes the impact of interest rate swaps, the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges (see Note 12—Derivative Financial Instruments for detailed information regarding fair value hedges and interest rate swaps).

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt outstanding as of December 31, 2010 and 2011 was $1.9 billion and $2.1 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated note. At December 31, 2011, maturities of our debt were as follows: $0.0 in 2012 and 2013; $250.0 million in 2014; $0.0 million in 2015; $250.0 million in 2016; and $1.6 billion thereafter.

2011 Debt Offering

In August 2011, we issued an additional $250.0 million of our 4.25% notes due 2021. We sold these notes at a price of 104.1% of their face value, or $260.2 million. Net proceeds from this offering, including accrued interest of $0.7 million, were $258.7 million after underwriting discounts of $1.6 million and other offering costs of $0.6 million. Proceeds from this debt offering were used to repay all of the borrowings outstanding under our revolving credit facility, which was $193.0 million at the time, and for general partnership purposes, including investments in capital expenditures.

Other Debt

Revolving Credit Facility. In October 2011, we entered into a new revolving credit facility. The new facility has total borrowing capacity of $800.0 million and matures in October 2016. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of December 31, 2011, there were no borrowings outstanding under this facility and $5.0 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets but decrease our borrowing capacity under the facility. Debt placement costs associated with our new revolving credit facility of $2.3 million are being amortized over the life of the facility.

The revolving credit facility described above requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the agreement) of no greater than 5.0 to 1.0. In addition, the revolving credit facility and the indentures under which our public notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions, and consolidate, merge or dispose of all or substantially all of our assets. The terms of our revolving credit facility exclude the financial impact of unrealized gains and losses of derivative agreements from the calculation of consolidated debt to EBITDA. We were in compliance with these covenants as of and during the year ended December 31, 2011.

During the years ending December 31, 2009, 2010 and 2011, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $64.3 million, $101.3 million and $111.7 million, respectively.

Interest Rate Derivatives. During 2011, we entered into interest rate swap agreements with respect to $100.0 million of our long-term debt, which were accounted for as fair value hedges, to hedge against changes in the fair value of a portion of our 6.40% notes due 2018. In third quarter 2011, we terminated and settled these interest rate swap agreements and received $6.1 million, of which $5.9 million was recorded as an adjustment to long-term debt that will be amortized over the remaining life of the notes and $0.2 million was recorded as a reduction of accrued interest.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2011 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$2,100.0	$—	$250.0	$250.0	$1,600.0
Interest obligations	1,101.3	122.7	235.6	198.8	544.2
Operating lease obligations	34.0	4.0	7.1	5.5	17.4
Pension and postretirement medical obligations(2)	67.7	13.3	32.5	1.6	20.3
Purchase commitments:					
Product purchase commitments(3)	35.4	35.4	—	—	—
Utility purchase commitments	7.5	5.7	1.4	0.2	0.2
Derivative instruments(4)	—	—	—	—	—
Equity-based incentive awards(5)	40.1	16.5	23.6	—	—
Environmental remediation(6)	8.9	3.4	2.3	2.7	0.5
Capital project purchase obligations	43.3	43.3	—	—	—
Maintenance obligations	15.7	15.7	—	—	—
Other purchase obligations	4.4	2.2	2.2	—	—
Total	$3,458.3	$262.2	$554.7	$458.8	$2,182.6

(1) At December 31, 2011, we had no borrowings outstanding under our revolving credit facility. For purposes of this table, we have reflected no assumed borrowings for any periods presented.

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

(3) We have an agreement with a supplier whereby we can purchase up to approximately 400,000 barrels of petroleum products per month until 2013. We have an offsetting agreement with a third party to sell these barrels at the same price as our purchases. Because we account for this buy-sell arrangement on a net basis, neither the product purchases nor the related product sales impact our consolidated statements of income. Related to these agreements, we have entered into a separate buy-or-make-whole agreement with the supplier for 13,000 barrels of petroleum products per day through January 31, 2013. Under the terms of this buy-or-make-whole agreement, if we do not purchase all of the barrels specified in the agreement, our supplier will sell the deficiency barrels in the open market. We are required to reimburse our supplier for any amounts in which they sell these deficiency barrels at prices lower than specified in our buy-or-make-whole agreement. We have not included any amounts in the table above for this commitment because we are unable to determine what the amounts, if any, of that commitment might be.

(4) As of December 31, 2011, we had entered into commodity-related derivative contracts representing 3.0 million barrels of petroleum products that we expect to sell in the future and 0.1 million barrels of petroleum products we expect to purchase in the future. At December 31, 2011, we had recorded a net liability of $1.5 million and made margin deposits of $26.9 million associated with these derivative agreements. We have excluded from this table the future net cash outflows, if any, under these derivative agreements and the amounts of future margin deposit requirements because those amounts are uncertain.

(5) Represents the grant date fair value of unit awards accounted for as equity plus the December 31, 2011 re-measured grant date fair value of award grants accounted for as liabilities. The liability is determined by multiplying the grant date per unit fair value by the number of unit award grants, multiplied by the percentage of the requisite service period completed, multiplied by the estimated payout percentage of the awards at December 31, 2011. Settlements of these awards will differ from these reported amounts primarily due to differences between actual and current estimates of payout percentages and forfeitures, changes in our unit price between December 31, 2011 and the vesting dates of the awards and completion of the remaining portion of the requisite service periods.

(6) During 2005, we entered into a 10-year agreement to reach contractual endpoint (as defined in the agreement) for 23 remediation sites. This contract obligates us to pay the remediation costs incurred by the contract counterparty associated with these 23 sites up to a maximum of $14.3 million. The amounts in the table above include the

estimated remaining amounts to be paid under this agreement ($2.1 million as of December 31, 2011) and the estimated timing of these payments. Additionally, this agreement requires us to pay the contract counterparty a performance bonus if the remediation sites are brought to contractual endpoint for less than $14.3 million. The table above includes our estimate of the performance bonus ($1.3 million) as of December 31, 2011. During 2006, we entered into a separate 10-year agreement with an independent contractor to remediate certain of our environmental sites. This contract obligated us to pay $16.2 million over a 10-year period. The amounts in the table above include the remaining amounts to be paid under this agreement ($5.5 million as of December 31, 2011) and the estimated timing of those payments based on project progress to date.

Environmental

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

Clean Air Act - Section 185 Contingent Liability.

Section 185 of Clean Air Act ("CAA") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas if the designated area within the state did not meet its attainment deadline. Imposition of the fee is mandated for each calendar year after the attainment date until the area is redesignated as an attainment area for ozone. 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") drafted a "Failure to Attain Rule" (the "Rule") to implement the requirements of CAA 185. The Rule was scheduled to be final in the spring of 2010 and would have provided for the collection of an annual failure to attain fee for emissions from calendar year 2008 forward. Under the Rule, the annual fees to be paid by entities within the Houston-Galveston non-attainment area would have been determined by the emissions from a facility that exceed an established baseline for each entity. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule.

In January 2010, the EPA issued guidance for states developing fee programs under CAA 185. In response to and based on the standards in the EPA's guidance, the TCEQ suspended the draft Rule and submitted a request for a determination by the EPA (a "Termination Determination") that the Houston-Galveston Region no longer qualified as a severe non-attainment area. Had the TCEQ's request for a Termination Determination been approved by the EPA, the requirement to assess a CAA 185 fee would have been terminated. Subsequent to the TCEQ's request for a Termination Determination, the Natural Resource Defense Counsel submitted a petition in federal court challenging the legality of the EPA's guidance. Based upon the EPA's belief and assertion that the guidance would be sustained in federal court, management determined the probability of the assessment of an annual fee for the Houston-Galveston area was remote.

In July 2011, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in the National Resource Defense Counsel case vacating the EPA's January 2010 guidance memorandum on states' CAA 185 equivalent programs. As a result of the court's ruling, the EPA has instructed the TCEQ that it is unable to approve the Termination Determination request.

Based on the recent court decisions and statements by the EPA, management believes that it is probable that the TCEQ will move forward with its CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility that we will not be assessed any CAA 185 fees at all. However, management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston area facilities and estimates that the range of fees that could be assessed to us for the periods from 2007 through 2010 to be between $6.4 million and $13.7 million. During 2011, after multiple discussions with the TCEQ, we recognized our best estimate of this liability, or $8.9 million, which we recorded as a long-term environmental liability. Additionally during 2011, we accrued $0.8 million for estimated fees associated with 2011 ongoing operations and $1.0 million related to an incident involving the buildup of excess water on the top of floating roof tanks, both of which were recorded as a long-term environmental liability.

Carbon Dioxide Emission Standards. The EPA has set a May 2013 compliance date for the reduction of carbon dioxide from the exhausts of large stationary engines. The EPA rule generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance; however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. A portion of our petroleum pipeline system uses engines to provide power to our pipeline pumps that are subject to the EPA rule, and our maintenance capital estimates include funding to comply with the EPA rule. Initial efforts to reduce emissions with catalytic converters have not been successful, and has led to our request of a compliance extension to the EPA. If we do not receive an extension, or are not able to modify or replace these engines by May 2013, sections of our petroleum pipeline system could experience capacity reductions or we could be assessed penalties until the required emission reductions are achieved.

Other Items

Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities, which exposes us to commodity price risk. We use NYMEX contracts and butane swap agreements to help manage this commodity price risk. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. We use and account for those NYMEX contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use butane swap agreements to hedge against changes in the price of butane we expect to purchase in the future as part of our petroleum products blending activity. As of December 31, 2011, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude linefill and tank bottom inventory. These contracts, which we are accounting for as fair value hedges, mature between January 2012 and November 2013. Through December 31, 2011, the cumulative amount of unrealized losses from these agreements was $6.4 million. These unrealized losses from these fair value hedges were recorded as adjustments to the asset being hedged. As a result, none of these unrealized losses impacted product sales.

Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 1.9 million barrels of petroleum products related to our petroleum products blending, fractionation and Houston-to-El Paso linefill management activities. These contracts mature between January and May 2012 and are being accounted for as economic hedges. Through December 31, 2011, the cumulative amount of net unrealized gains associated with these agreements was $5.2 million, all of which was recognized in 2011.

- NYMEX contracts covering 0.4 million barrels of petroleum products related to our pipeline product overages that matured in January 2012. Through December 31, 2011, the cumulative amount of unrealized losses associated with these agreements was $0.4 million. We recorded these losses as an increase in operating expenses, all of which was recognized during 2011.

- Butane swap positions to purchase 0.1 million barrels of butane that mature between January and March 2012. Through December 31, 2011, the cumulative amount of unrealized losses associated with these agreements was less than $0.1 million. We recorded these losses as an increase in product purchases, all of which were recognized in 2011.

Settled Derivative Contracts

Additionally, related to physical product sales during 2011, we recognized gains of $7.7 million on NYMEX contracts designated as cash flow hedges that settled during 2011 and losses of $28.4 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2011.

The following table provides a summary of the mark-to-market gains and losses associated with NYMEX contracts and the accounting periods in which the gains and losses were recognized in our consolidated statements of income for the years ended December 31, 2009, 2010 and 2011 (in millions):

2009		
NYMEX losses recorded in 2009 that were associated with physical product sales during 2009	$(30.3	)
NYMEX losses recorded in 2009 that were associated with future physical product sales	(8.3	)
Total NYMEX losses that impacted product sales revenues during 2009	$(38.6	)
2010		
NYMEX losses recorded in 2010 that were associated with physical product sales during 2010	$(6.8	)
NYMEX losses recorded in 2010 that were associated with future physical product sales	(14.9	)
Total NYMEX losses that impacted product sales revenues during 2010	$(21.7	)
2011		
NYMEX losses recorded in 2011 that were associated with physical product sales during 2011	$(20.7	)
NYMEX gains recorded in 2011 that were associated with future physical product sales	5.2	
Total NYMEX losses that impacted product sales revenues during 2011	$(15.5	)

Pipeline Tariff Increase. The FERC regulates the rates charged on interstate common carrier pipeline operations primarily through an index methodology, which establishes the maximum amount by which tariffs can be adjusted each year. Approximately 35% of our tariffs are subject to this indexing methodology while the remaining 65% of the tariffs can be adjusted at our discretion based on competitive factors. In December 2010, the FERC approved the indexing methodology to be used for the five-year period beginning in July 2011 equal to the annual change in the producer price index for finished goods ("PPI-FG") plus 2.65%. Based on preliminary estimates of the PPI-FG for

2011, we would expect to increase virtually all of our tariffs by 8.6% on July 1, 2012.

Unrecognized Product Gains. Our petroleum terminals operations generate product overages and shortages that result from metering inaccuracies and product evaporation, expansion, releases and contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum terminals experience net product overages, we have product on hand for which we have no cost basis. Therefore, these net overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The net unrecognized product overages for our petroleum terminals operations had a market value of approximately $2.2 million as of December 31, 2011. However, the actual amounts we will recognize in future periods will depend on product prices at the time the associated barrels are either sold or used to offset future product losses.

Critical Accounting Estimates

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

Environmental Liabilities

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

A defined process for project reviews is integrated into our system integrity plan. Each year our remediation project managers meet to evaluate, in detail, the known environmental sites. The purpose of the annual project review is to assess all aspects of each project, evaluating what actions will be required to achieve regulatory compliance and estimating the costs and timing to execute the regulatory phases that can be reasonably estimated. During the site-specific evaluations, we utilize all known information in conjunction with professional judgment and experience to determine the appropriate approach to remediation and to assess liabilities. The process to achieve regulatory compliance consists of site investigation/delineation, site remediation and long-term monitoring. Each of these phases can, and often does, include unknown variables that complicate the task of evaluating the estimated costs to completion. At each accounting period-end we re-evaluate our environmental estimates taking into account any new incidents that have occurred since the last annual meeting of the remediation project managers, any changes in the site situation remediation, including work to date, additional findings or changes in federal or state regulations and changes in cost estimates. Changes in our environmental liabilities since December 31, 2009 were as follows (in millions):

Balance 12/31/09	2010 Accruals	Expenditures	Acquisitions	Balance 12/31/10	2011 Accruals	Expenditures	Balance 12/31/11
$34.4	$12.9	$(14.9)	$0.4	$32.8	$29.2	$(12.4)	$49.6

During 2010, we increased our environmental liability accruals by $12.9 million, of which $6.0 million was due to product releases which occurred during 2010 and $6.9 million related to historical releases. At December 31, 2010, we had recognized $2.2 million of receivables from insurance carriers associated with environmental claims.

During 2011, we increased our environmental liability accruals by $29.2 million, of which, $10.7 million was related to potential air emission fees (see Clean Air Act - Section 185 Contingent Liability, above), $10.6 million was due to product releases which occurred during 2011 and $7.9 million related to historical releases. At December 31, 2011, we had recognized $7.7 million of receivables from insurance carriers associated with environmental claims.

We based our environmental liabilities at December 31, 2011 on estimates that are subject to change, and any changes to these estimates would affect our results of operations and financial position. For example, if our environmental liabilities increased by 25%, our operating expenses would increase by $12.4 million and operating profit would decrease $12.4 million, or 2%, net income would decrease $12.4 million, or 3%, and basic and diluted net income per limited partner unit would each decrease $0.11. Such a change of that size would not materially impact our liabilities or equity. Further, the impact of such an increase of that size in environmental costs would likely not affect our liquidity because, even with the increased costs, we would still comply with the covenants of our debt agreements as discussed above under Liquidity and Capital Resources-Liquidity.

Pension and Postretirement Obligations

We sponsor two union pension plans covering certain employees (“USW plan” and “IUOE plan”), a pension plan for all non-union employees and certain union employees (“Salaried plan”) and a postretirement benefit plan for selected employees. Various estimates and assumptions directly affect net periodic benefit expense and obligations for these plans. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase and the assumed health care cost trend rate. Management reviews these assumptions annually and makes adjustments as necessary.

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

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
Pension benefits:				
Discount rate	$ (3,185)	$ 3,872	$(15,655)	$ 19,891
Expected long-term rate of return on plan assets	(606)	761	—	—
Rate of compensation increase	2,456	(892)	7,282	(6,138)
Other postretirement benefits:				
Discount rate	(454)	567	(3,699)	4,822
Assumed health care cost trend rate	683	(553)	3,877	(3,139)

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

We estimate the long-term expected rate of return on plan assets using expectations of capital market results, which includes an analysis of historical results as well as forward-looking projections. We base these capital market expectations on a long-term period and on our investment strategy and asset allocation. We develop our estimates using input from several external sources, including consultation with our third-party independent investment consultant. We develop the forward-looking capital market projections using a consensus of expectations by economists for inflation and dividend yield, along with expected changes in risk premiums. Because our determined rate is an estimate of future results, it could be significantly different from actual results.

The capital markets have improved substantially since 2008 and the benefit plans' assets reflect these improvements. While the 2009 and 2010 investment performances were greater than our expected rates of return for these years, the investment performance for 2011 was 4.2% less than our expected rates of return. The expected rates of return on plan assets are long-term in nature; therefore, short-term market performance does not significantly affect these rates. Changes to our asset allocation also affect these expected rates of return. The expected long-term rate of return on plan assets used for our Salaried and USW plans has been approximately 7.0% since 2004. Since 2009, we have estimated the long-term rate of return on the IUOE plan assets at 3.3% primarily because of the asset allocation of that fund. The 2011 actual return on plan assets for our Salaried and USW pension plans was a gain of approximately 2.7% and 2.9%, respectively. Through December 2011, the weighted-average rate of return on pension plan assets for the 8-year period we have controlled the plans was approximately 4.9%, which was significantly affected by the 14.2% loss experienced in 2008.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and expense to increase. We base the assumed health care cost trend rates on national trend rates adjusted for our actual historical claims experience and plan design. An increase in this rate causes the other postretirement benefit obligation and expense to increase.

Equity-Based Incentive Compensation Expense

Each year, the compensation committee of our general partner's board of directors has approved performance-based award grants of phantom units to key employees. The majority of the awards granted in 2009, 2010 and 2011 have three-year vesting periods and payouts of the performance awards are based on actual results as measured against a financial metric goal.

The financial metric for the 2009, 2010 and 2011 performance awards was distributable cash flow per limited partner unit outstanding excluding the impact of certain commodity-related activities (“adjusted DCF”). Generally, unit awards are granted in January of the first year of the three-year vesting period of the awards. At the time the awards are granted, the compensation committee establishes threshold, target and stretch adjusted DCF metric goals for the third year of those awards' vesting period. Adjusted DCF performance in that third year determines the payout percentage of the awards as follows: adjusted DCF at or below the threshold metric results in a 0% payout, adjusted DCF at the target metric results in a 100% payout and adjusted DCF at or above the stretch metric results in a 200% payout, with results between the established metrics being interpolated.

Under Accounting Standards Codification ("ASC") 718, Compensation-Stock Compensation,we classify performance awards as either equity or liabilities. Each period's compensation expense for awards classified as equity is calculated as the number of unit awards classified as equity less estimated forfeitures, multiplied by the per unit grant date fair value of those awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense. We re-measure unit awards classified as liabilities at fair value on the close of business at each reporting period end until settlement date. Fair value at each re-measurement date is the closing price of our limited partner units at each period end reduced by the present value of any projected per unit distributions during the remainder of the requisite service period that will not be paid to the participant. Each period's compensation expense for unit awards classified as liabilities is the number of unit awards classified as liabilities less estimated forfeitures, multiplied by the re-measured fair value of the awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense.

Accounting for these performance awards requires management to make a number of judgments and assumptions; however, the key assumption in determining our equity-based compensation expense is management's estimate of the final payout percentage, which can range from 0% to 200% of the performance award. At the end of each accounting period, management estimates the expected payout of each year's performance award. Changes in this estimate can significantly affect equity-based compensation expense, particularly when those changes are made in the last year of the three-year vesting period. During the first year of a performance award's vesting period, the estimated payout percentage is generally at 100% because management assumes that actual adjusted DCF results will be at target unless there are exceptionally strong indicators to the contrary. During the second year of the vesting period, management adjusts the estimated payout percentages from 100% only if there are strong indicators that actual adjusted DCF for the last year of the vesting period will be higher or lower than target. Management evaluates the strength of the economy, results from completed acquisitions, expense and revenue trends and a number of other factors when making these determinations. During the third and final year of the vesting period, management adjusts the payout percentage primarily to reflect actual and forecast adjusted DCF results as the year progresses and finally to the actual payout percentage at the end the vesting period.

During 2009, management assumed the payout percentage for the 2009 performance awards would be 100% because there were no exceptionally strong indicators that adjusted DCF for the final year of the vesting period would be different than target. Equity-based compensation expense for these awards for the year ended December 31, 2009 was $2.1 million. During 2010, management decided to increase the estimated payout percentages for the 2009 performance awards to 150%, primarily because of improving economic conditions, strong acquisition results for 2010 and a strong outlook for 2011. Equity-based compensation expense for these awards for the year ended December 31, 2010 increased to $5.0 million. During 2011, management increased the estimated payout percentage for these awards to 200%, which was the actual payout amount, and equity-based compensation expense for these awards for the year ended December 31, 2011 was $8.7 million.

During 2010, management assumed the payout percentage for the 2010 performance awards would be 100% because there were no exceptionally strong indicators that adjusted DCF for the final year of the vesting period would be different than target. Equity-based compensation expense for these awards for the year ended December 31, 2010 was $2.5 million. During 2011, management increased the estimated payout percentage for these awards to 125% based on strong actual and anticipated acquisition and capital project results. Equity-based compensation expense for these awards for the year ended December 31, 2011 was $4.7 million.

During 2011, management initially assumed the payout percentage for the 2011 performance awards would be 100%; however, during the fourth quarter of 2011, because of the exceptionally strong indicators that adjusted DCF for the final year of the vesting period would be above target, the estimated payout percentage for these awards was increased to 125%. The exceptionally strong indicators of higher adjusted DCF for the 2013 year is primarily due to anticipated capital project results. Equity-based compensation expense for these awards for the year ended December 31, 2011 was $3.7 million.

Valuation of Assets

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

During 2009 and 2010, we completed acquisitions accounted for as business combinations with a combined value of $390.6 million and $291.3 million, respectively. For all material acquisitions accounted for as business combinations, we engage the services of an independent appraiser to assist us in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of our management. We base our estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

Goodwill and Impairment of Long-Lived Assets

Goodwill. At December 31, 2010 (as adjusted) and 2011, we had recognized goodwill of $53.3 million. Goodwill resulting from a business combination is not subject to amortization; however, we test goodwill for impairment annually or more frequently when indicators of impairment exist. As required by ASC 350, Goodwill and Other, we test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit using the equity premise method. We use the present value of expected net cash flows and market multiple analyses to determine the estimated fair values of our reporting segments. The impairment test under ASC 350 requires the use of projections, estimates and assumptions as to the future performance of our operations, including anticipated future revenues, expected future operating costs, discount factor and the terminal value of reporting unit. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Any such impairment losses recognized could be material to our results of operations. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our reporting segments. Based on our assessment at December 31, 2011 and 2010, we do not believe our goodwill was impaired, and we did not record a charge associated with ASC 350 during 2009, 2010 or 2011.

Impairment of Long-Lived Assets. As prescribed by ASC 360-10-05, Property, Plant and Equipment-General-Impairment or Disposal of Long-Lived Assets, we assess property, plant and equipment ("PP&E") for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include, among others, the nature of the asset, the projected future economic benefit of the asset, changes in regulatory and political environments and historical and future cash flow and profitability measurements. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, we recognize an impairment charge for the excess of carrying value of the asset over its estimated fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses and the outlook for national or regional market supply and demand conditions. We base the impairment reviews and calculations used in our impairment tests on assumptions that are consistent with our business plans and long-term investment decisions.

We recognized no impairments during 2009 and 2010 and impairments recognized during 2011 were insignificant. An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and impairment calculations is not practicable, given the broad range of our PP&E and the number of assumptions involved in the estimates. Favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

New Accounting Pronouncements

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-08, Intangibles-Goodwill and Other (Topic 350): Testing Goodwill for Impairment, which modifies the test for goodwill intangibles. Under this ASU, entities are no longer required to calculate the fair value of a reporting unit unless they determine that it is more likely than not that a reporting unit's fair value is less than its carrying amount. This ASU is effective for periods beginning after December 15, 2011. We expect that our adoption of this ASU in the first quarter of 2012 will have no impact on our results of operations, financial position or cash flows.

52

In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income, which requires either that the income statement include other comprehensive income or a separate comprehensive income statement be reported immediately after the income statement. The option to report other comprehensive income in the statement of owner's equity has been eliminated. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted; however, the FASB is considering delaying the effective date because some entities are experiencing difficulties with its implementation. We adopted this ASU in first quarter of 2011, which had no impact on our results of operations, financial position or cash flows.

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs which amends ASC 820, Fair Value Measurement. This ASU amends ASC 820 and results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and international financial reporting standards. The amendments in this ASU change the wording used to describe many of the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements; however, the amendment’s requirements do not extend the use of fair value accounting, and for many of the requirements, the FASB does not intend for the amendments to result in a change in the application of the requirements in the “Fair Value Measurement” Topic of the Codification. Additionally, ASU No. 2011-04 includes some enhanced disclosure requirements, including an expansion of the information required for Level 3 fair value measurements. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Early adoption is not permitted. We expect that our adoption of this ASU in the first quarter of 2012 will not have a material impact on our results of operations, financial position or cash flows.

On February 24, 2010, the FASB issued ASU No. 2010-09, Subsequent Events (Topic 855): Amendments to Certain Recognition and Disclosure Requirements. This ASU amended the guidance on subsequent events to remove the requirement for entities that file financial statements with the SEC to disclose the date through which it has evaluated subsequent events. This ASU was effective on its issuance date. Our adoption of this ASU did not have an impact on our financial position, results of operations or cash flows.

On January 21, 2010, the FASB issued ASU No. 2010-06, Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This ASU required disclosure of: (i) separate fair value measurements for each class of assets and liabilities, (ii) significant transfers between level 1 and level 2 in the fair value hierarchy and the reasons for such transfers, (iii) gains and losses for the period and purchases, sales, issuances and settlements for Level 3 fair value measurements, (iv) transfers into and out of Level 3 of the hierarchy and the reasons for such transfers and (v) the valuation techniques applied and inputs used in determining Level 2 and Level 3 measurements for each class of assets and liabilities. This ASU was generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances and settlements in the Level 3 reconciliation were effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Our adoption of this ASU did not have a material impact on our financial position, results of operations or cash flows.

Related Party Transactions

We own a 50% interest in a crude oil pipeline company and receive a management fee for its operation. We received operating fees from this company of $0.8 million each year in 2009, 2010 and 2011. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

Barry R. Pearl became an independent member of our general partner's board of directors on May 26, 2009. Mr. Pearl is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase petroleum products from subsidiaries of Targa. For the periods of May 26, 2009 through December 31, 2009 and the years ended December 31, 2010 and 2011, we made purchases from subsidiaries of Targa of $0.2 million, $1.8 million and $11.7 million, respectively. These purchases were made on the same terms as comparable third-party transactions.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards that would otherwise have been forfeited would not be forfeited. See Note 14–Long-Term Incentive Plan in our consolidated financial statements included in this filing for a discussion of the changes made to Mr. Wellendorf's phantom unit awards.

Prior to the simplification of our capital structure (see Note 2–Summary of Significant Accounting Policies), we operated under a services agreement with an affiliate for our employee payroll and benefits. The following table summarizes affiliate costs and expenses in 2009 that are included in the accompanying consolidated statements of income (in thousands):

MGG Midstream Holdings GP, LLC—allocated operating expenses	$69,523
MGG Midstream Holdings GP, LLC—allocated G&A expenses	41,890

Prior to the simplification of our capital structure in September 2009, our partnership agreement entitled our general partner to receive approximately 50% of any incremental cash distributed per limited partner unit once certain target distributions per unit were exceeded. Since Magellan Midstream Holdings, L.P. ("Holdings") owned our general partner prior to the simplification, Holdings benefited from these distributions. For a portion of 2009 prior to the simplification, distributions paid to Holdings by us totaled $70.4 million.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "believes," "continue," "could," "estimates," "expects," "forecasts," "goal," "guidance," "intends," "may," "might," "plans," "potential," "projects," "scheduled," "should" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

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

- overall demand for refined petroleum products, natural gas liquids, crude oil and ammonia in the U.S.;
- price fluctuations for petroleum products, crude oil and natural gas liquids and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties or lenders;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy and maintain adequate liquidity;
- development of alternative energy sources, including without limitation, solar power, wind power and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, regulatory developments or other trends that could affect demand for our services;
- changes in the throughput or interruption in service on petroleum pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our petroleum terminals;
- changes in supply patterns for our storage terminals due to geopolitical events;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
-

the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;

- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards, equipment failures, system failures or unforeseen interruptions for which we are not adequately insured;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify growth projects or to complete identified growth projects on time and at projected costs;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- actions by rating agencies concerning our credit ratings;

- our ability to receive all necessary approvals, consents and permits by applicable governmental entities within the time-line anticipated by project schedules for new or modified assets;
- our ability to obtain all necessary approvals, consents and permits required to operate our assets;
- our ability to promptly obtain all necessary materials and supplies required for construction, and to construct facilities without labor or contractor problems;
- risks inherent in the use of information systems in our business and implementation of new software and hardware;
- changes in laws and regulations that govern the product quality specifications that could impact our ability to produce gasoline volumes through our blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we are or become subject, including tax withholding issues, safety, security, employment and environmental laws and regulations, including laws and regulations designed to address climate change;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability of third parties to perform on their contractual obligations to us;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

We use derivatives to help us manage commodity price risk. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2011, we had commitments under forward purchase contracts for product purchases of approximately 0.4 million barrels that are being accounted for as normal purchases totaling approximately $32.1 million, and we had commitments under forward sales contracts for product sales of approximately 0.1 million barrels that are being accounted for as normal sales totaling approximately $17.3 million.

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from activities in which we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment and we designate and account for these as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment or, are otherwise undesignated as cash flow or fair value hedges, as economic hedges. We also use butane swap agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At December 31, 2011, we had open NYMEX contracts representing 3.0 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane swap positions of 0.1 million barrels of butane we expect to purchase in the future.

At December 31, 2011, the fair value of our open NYMEX contracts was a net liability of $1.5 million and the fair value of our butane swap agreements was a liability of less than $0.1 million. Combined, the net liability was $1.5 million, of which $4.9 million was recorded as a current asset to energy commodity derivatives contracts and $6.4 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

At December 31, 2011, open NYMEX contracts representing 2.3 million barrels of petroleum products did not qualify for hedge accounting treatment. A $1.00 per barrel increase in the price of these NYMEX contracts for reformulated gasoline blendstock for oxygen blending (“RBOB”) gasoline or heating oil would result in a $2.3 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $2.3 million increase in our product sales revenues. However, the increases or decreases in product sales revenues we recognize from our open NYMEX contracts will be substantially offset by higher or lower product sales revenues when the physical sale of the product occurs. 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.

At December 31, 2011, open butane swap contracts representing 0.1 million barrels of butane were designated as economic hedges. A $1.00 per barrel increase in the price of butane would result in a $0.1 million decrease in our product purchases and a $1.00 per barrel decrease in the price of butane would result in a $0.1 million increase in our product purchases. However, the increases or decreases in product purchases we recognize from our open butane price swap contracts will be substantially offset by higher or lower product purchases when the physical purchase of the product occurs. 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.

Interest Rate Risk

At December 31, 2011, we had no variable rate debt outstanding, including on our revolving credit facility. Our revolving credit facility has total borrowing capacity of $800.0 million, from which we could borrow in the future. To the extent we borrow funds under this facility in any future period, those borrowings would bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility.

Item 8. Financial Statements and Supplementary Data

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention and timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on our financial statements.

Management believes that the design and operation of our internal control over financial reporting at December 31, 2011 were effective.

We assessed our internal control system using the criteria for effective internal control over financial reporting described in “Internal Control-Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO” criteria). As of December 31, 2011, based on the results of our assessment, management believed that we had no material weaknesses in internal control over our financial reporting. We maintained effective internal control over financial reporting as of December 31, 2011 based on COSO criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2011. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2011, is included herein under the heading “Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting.”

By: /S/ MICHAEL N. MEARS
Chairman of the Board, President, Chief Executive Officer and Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

By: /S/ JOHN D. CHANDLER
Senior Vice President and Chief Financial Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

Report of Independent Registered Public Accounting Firm
on Internal Control Over Financial Reporting

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

We have audited Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Magellan Midstream Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Magellan Midstream Partners, L.P.'s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, owners' equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2012

58

Report of Independent Registered Public Accounting Firm
The Board of Directors of Magellan GP, LLC
General Partner of Magellan Midstream Partners, L.P.
and the Limited Partners of Magellan Midstream Partners, L.P.

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, owners' equity and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2012

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

	Year Ended December 31,		
	2009	2010	2011
Transportation and terminals revenues	$678,945	$793,599	$893,369
Product sales revenues	334,465	763,090	854,528
Affiliate management fee revenue	761	758	770
Total revenues	1,014,171	1,557,447	1,748,667
Costs and expenses:			
Operating	257,635	282,212	306,415
Product purchases	280,291	668,585	706,270
Depreciation and amortization	97,216	108,668	121,179
General and administrative	84,049	95,316	98,669
Total costs and expenses	719,191	1,154,781	1,232,533
Equity earnings	3,431	5,732	6,763
Operating profit	298,411	408,398	522,897
Interest expense	73,357	96,379	108,869
Interest income	(660)	(140)	(61)
Interest capitalized	(3,510)	(2,943)	(3,174)
Debt placement fee amortization	1,112	1,401	1,831
Other (income) expense, net	(24)	750	—
Income before provision for income taxes	228,136	312,951	415,432
Provision for income taxes	1,661	1,371	1,866
Net income	$226,475	$311,580	$413,566
Allocation of net income (loss):			
Noncontrolling owners' interests	$99,729	$(397)	$(63)
Limited partners' interest	126,746	311,977	413,629
Net income	$226,475	$311,580	$413,566
Basic net income per limited partner unit	$2.22	$2.85	$3.67
Diluted net income per limited partner unit	$2.22	$2.85	$3.66
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	57,115	109,485	112,837
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	57,145	109,561	112,987

See notes to consolidated financial statements.

60

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

	Year Ended December 31,		
	2009	2010	2011
Net income	$226,475	$311,580	413,566
Other comprehensive income:			
Net gain (loss) on commodity hedges	(6,804)	(4,283)	7,739
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	(164)	(164)
Reclassification of net loss (gain) on commodity hedges to product sales revenues	5,058	5,438	(7,739)
Reclassification of loss on discontinuance of cash flow hedge to product sales revenues	—	591	—
Settlement cost and amortization of prior service credit and actuarial loss	1,256	106	1,117
Adjustment to recognize the funded status of postretirement plans	9,771	(4,783)	(37,058)
Total other comprehensive income (loss)	9,117	(3,095)	(36,105)
Comprehensive income	235,592	308,485	377,461
Comprehensive income (loss) attributable to non-controlling owners' interest in consolidated subsidiaries	101,420	(397)	(63)
Comprehensive income attributable to partners' capital	$134,172	$308,882	$377,524

See notes to consolidated financial statements.

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

	December 31, 2010	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$7,483	$209,620
Restricted cash	14,379	—
Trade accounts receivable (less allowance for doubtful accounts of $106 and $68 at December 31, 2010 and 2011, respectively)	92,192	82,497
Other accounts receivable	6,175	10,079
Inventory	216,408	258,860
Energy commodity derivatives contracts	—	4,914
Energy commodity derivatives deposits	22,302	26,917
Reimbursable costs	13,870	5,891
Other current assets	11,774	13,412
Total current assets	384,583	612,190
Property, plant and equipment	3,881,275	4,080,484
Less: accumulated depreciation	716,054	830,762
Net property, plant and equipment	3,165,221	3,249,722
Equity investments	23,728	35,594
Long-term receivables	1,167	2,534
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $11,964 and $14,813 at December 31, 2010 and 2011, respectively)	16,924	15,176
Debt placement costs (less accumulated amortization of $5,439 and $5,799 at December 31, 2010 and 2011, respectively)	11,871	14,615
Tank bottom inventory	57,937	59,473
Other noncurrent assets	3,209	2,437
Total assets	$3,717,900	$4,045,001
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$41,425	$66,384
Accrued payroll and benefits	32,393	30,184
Accrued interest payable	35,799	40,547
Accrued taxes other than income	26,953	27,570
Environmental liabilities	12,202	17,852
Deferred revenue	34,733	39,983
Accrued product purchases	47,324	59,800
Energy commodity derivatives contracts	11,790	—
Other current liabilities	32,428	28,735

Total current liabilities	275,047	311,055
Long-term debt	1,906,148	2,151,775
Long-term pension and benefits	28,965	67,080
Other noncurrent liabilities	17,597	19,905
Environmental liabilities	20,572	31,783
Commitments and contingencies		
Owners' equity:		
Partners' capital:		
Limited partner unitholders (112,481 units and 112,737 units outstanding at December 31, 2010 and 2011, respectively)	1,466,404	1,510,604
Accumulated other comprehensive loss	(11,096)	(47,201)
Total partners' capital	1,455,308	1,463,403
Non-controlling owners' interests in consolidated subsidiaries	14,263	—
Total owners' equity	1,469,571	1,463,403
Total liabilities and owners' equity	$3,717,900	$4,045,001

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2009	2010	2011
Operating Activities:			
Net income	$226,475	$311,580	$413,566
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	97,216	108,668	121,179
Debt placement fee amortization	1,112	1,401	1,831
Loss on sale and retirement of assets	5,529	1,062	8,599
Equity earnings	(3,431)	(5,732)	(6,763)
Distributions from equity investments	3,431	4,853	5,598
Equity-based incentive compensation expense	9,622	18,899	17,710
Amortization of net prior service credit and net actuarial loss	1,256	106	1,117
Changes in components of operating assets and liabilities (Note 3)	(71,773)	(16,181)	14,486
Net cash provided by operating activities	269,437	424,656	577,323
Investing Activities:			
Property, plant and equipment:			
Additions to property, plant and equipment	(216,698)	(221,419)	(199,665)
Proceeds from sale and disposition of assets	338	8,300	6,299
Increase (decrease) in accounts payable related to capital expenditures	921	(3,432)	2,126
Acquisitions of businesses	(390,606)	(291,292)	—
Acquisition of tank bottom inventory	—	(53,017)	—
Acquisition of assets	—	(29,300)	(17,807)
Acquisition of non-controlling owners' interests	—	—	(40,500)
Equity investments	—	—	(10,701)
Distributions in excess of equity investment earnings	1,127	—	—
Other	—	—	1,507
Net cash used by investing activities	(604,918)	(590,160)	(258,741)
Financing Activities:			
Distributions paid	(285,758)	(318,817)	(350,892)
Net borrowings (repayments) under revolver	31,600	(86,600)	(15,000)
Borrowings under long-term notes	568,699	298,899	260,914
Debt placement costs	(4,357)	(2,378)	(4,575)
Net receipt from financial derivatives	5,335	16,238	5,926
Increase (decrease) in outstanding checks	2,955	2,393	(5,408)
Settlement of tax withholdings on long-term incentive compensation	(3,450)	(3,371)	(7,410)
Issuance of limited partner units	—	258,407	—
Capital contributed by non-controlling owners	—	4,361	—
Costs associated with the simplification of capital structure	(13,287)	(313)	—
Net cash provided (used) by financing activities	301,737	168,819	(116,445)
Change in cash and cash equivalents	(33,744)	3,315	202,137
Cash and cash equivalents at beginning of period	37,912	4,168	7,483
Cash and cash equivalents at end of period	$4,168	$7,483	$209,620
Supplemental non-cash financing activities:			
	$1,943	$2,034	$4,315

Issuance of MMP limited partner units in settlement of long-term incentive plan awards			
Non-cash capital contributed by non-controlling owners	$—	$10,299	$—

See notes to consolidated financial statements.

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

	Partners' Capital			
	Limited Partners	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2009	$68,063	$ (340)	$ 1,186,409	$1,254,132
Comprehensive income:				
Net income	126,746	—	99,729	226,475
Net gain (loss) on commodity hedges	—	(7,430)	626	(6,804)
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(44)	(120)	(164)
Reclassification of net loss (gain) on commodity hedges to product sales revenues	—	5,308	(250)	5,058
Amortization of net prior service credit and net actuarial loss	—	333	923	1,256
Adjustment to recognize the funded status of postretirement plans	—	9,259	512	9,771
Total comprehensive income	126,746	7,426	101,420	235,592
Distributions	(143,147)	—	(142,611)	(285,758)
Equity method incentive compensation expense	6,894	—	—	6,894
Costs associated with the simplification of our capital structure	(13,287)	—	—	(13,287)
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	(4,406)	—	6,349	1,943
Issuance of MMP limited partner units in settlement of special unit awards	377	—	—	377
Settlement of tax withholdings on long-term incentive compensation	(3,450)	—	—	(3,450)
Issuance of MMP limited partner units pursuant to the simplification (Note 2)	1,166,654	(15,087)	(1,151,567)	—
Other	(89)	—	—	(89)
Balance, December 31, 2009	$1,204,355	$ (8,001)	$—	$1,196,354
Comprehensive income:				
Net income (loss)	311,977	—	(397)	311,580
Net loss on commodity hedges	—	(4,283)	—	(4,283)
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(164)	—	(164)
Reclassification of net loss on commodity hedges to product sales revenues	—	5,438	—	5,438
Reclassification of loss on discontinuance of cash flow hedge to product sales revenues	—	591	—	591
Amortization of net prior service credit and net actuarial loss	—	106	—	106
Adjustment to recognize the funded status of postretirement plans	—	(4,783)	—	(4,783)

Total comprehensive income (loss)	311,977	(3,095)	(397)	308,485
Distributions	(318,817)	—	—	(318,817)
Issuance of MMP limited partner units	258,407	—	—	258,407
Equity method incentive compensation expense	12,233	—	—	12,233
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	2,034	—	—	2,034
Settlement of tax withholdings on long-term incentive compensation	(3,371)	—	—	(3,371)
Capital contributed by non-controlling owners	—	—	14,660	14,660
Other	(414)	—	—	(414)
Balance, December 31, 2010	$1,466,404	$ (11,096)	$ 14,263	$1,469,571

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENT OF OWNERS' EQUITY—(Continued)
(In thousands)

	Partners' Capital			
	Limited Partners	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2011	$1,466,404	$(11,096)	$14,263	$1,469,571
Comprehensive income:				
Net income (loss)	413,629	—	(63)	413,566
Net gain on commodity hedges	—	7,739	—	7,739
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(164)	—	(164)
Reclassification of net gain on commodity hedges to product sales revenues	—	(7,739)	—	(7,739)
Settlement cost and amortization of net prior service credit and net actuarial loss	—	1,117	—	1,117
Adjustment to recognize the funded status of postretirement plans	—	(37,058)	—	(37,058)
Total comprehensive income (loss)	413,629	(36,105)	(63)	377,461
Distributions	(350,892)	—	—	(350,892)
Equity method incentive compensation expense	11,043	—	—	11,043
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	4,315	—	—	4,315
Settlement of tax withholdings on long-term incentive compensation	(7,410)	—	—	(7,410)
Acquisition of non-controlling owners' interest	(26,300)	—	(14,200)	(40,500)
Other	(185)	—	—	(185)
Balance, December 31, 2011	$1,510,604	$(47,201)	$—	$1,463,403

See notes to consolidated financial statements.

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

1. Organization and Description of Business

Organization

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

We operate and report in three business segments: the petroleum pipeline system, the petroleum terminals and the ammonia pipeline system. Our reportable segments offer different products and services and are managed separately because each requires different marketing strategies and business knowledge.

Description of Business

Petroleum Pipeline System. Our petroleum pipeline system includes approximately 9,600 miles of pipeline and 50 terminals that provide transportation, storage and distribution services. Our petroleum pipeline system covers a 13-state area extending from Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. The products transported on our pipeline system are primarily gasoline, distillates, LPGs, aviation fuels and crude oil. Product originates on the system from direct connections to refineries, at 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. We have a 50% interest in a crude oil pipeline company that owns a 135-mile pipeline 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. Our petroleum products blending and fractionation activities are also included in the petroleum pipeline system segment.

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 27 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 consists of an 1,100-mile ammonia pipeline and six company-owned terminals. Shipments on the pipeline primarily originate from ammonia production plants located in Texas and Oklahoma for transport to terminals throughout the Midwest. Our customers use the ammonia transported through our system primarily as nitrogen fertilizer.

2. Summary of Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include the petroleum pipeline system, the petroleum terminals and the ammonia pipeline system. We consolidated all entities in which we have ownership interests, except three 50%-or-less-owned investments that we do not control and for which we have determined are not variable interest entities. Accordingly, we apply the equity method of accounting for these entities. We have eliminated all intercompany transactions.

Simplification. In September 2009, pursuant to a Simplification Agreement, approximately 39.6 million of our limited partner units were issued to unitholders of Magellan Midstream Holdings, L.P. ("Holdings"), Magellan Midstream Holdings GP, LLC, Holdings' general partner and MMP GP were contributed to us by Holdings and Holdings was dissolved (collectively, the "simplification"). These financial statements were originally the financial statements of Holdings prior to the effective date of the simplification. Although Holdings was the surviving entity for accounting purposes, Magellan Midstream Partners, L.P. was the surviving entity for legal purposes and the name on these financial statements was changed from "Magellan Midstream

Holdings, L.P." to "Magellan Midstream Partners, L.P." For historical reporting purposes, the simplification was accounted for as a reverse unit split of 0.6325 to 1.0 and the weighted average limited partner units outstanding used for basic and diluted earnings per unit calculations were Holdings' historical weighted average limited partner units outstanding adjusted for the reverse unit split. Because of the simplification, both Holdings' general partner and MMP GP became our wholly owned subsidiaries, our requirement to pay incentive distribution rights was eliminated and we acquired all of the non-controlling owners' interests that existed at the time of the simplification.

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

Cash Equivalents. Cash and cash equivalents include demand and time deposits and other highly marketable securities with original maturities of three months or less when acquired. We periodically assess the financial condition of the institutions where we hold these funds and at December 31, 2010 and 2011, we believed that our credit risk was minimal.

Restricted Cash. Restricted cash at December 31, 2010 included cash held by Magellan Crude Oil, LLC ("MCO") that was to be used for tank construction and was unavailable to us at that time. In February 2011, we acquired the non-controlling owners' interest in MCO and since that time there have been no restrictions on our cash.

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

Inventory Valuation. Inventory is comprised primarily of refined petroleum products, natural gas liquids, transmix, crude oil and additives, which are stated at the lower of average cost or market. During 2011, we recorded lower-of-average-cost-or-market adjustments of $0.6 million and $0.4 million to our transmix and refined petroleum products inventory, respectively. These adjustments were recorded as a component of product purchases on the consolidated statement of income included with these financial statements.

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

We depreciate most of our assets individually on a straight-line basis over their useful lives; however, we group the individual components of certain assets, such as some of our older tanks, together into a composite asset, and we depreciate those assets using a composite rate. We assign asset lives based on reasonable estimates when we place an asset into service. Subsequent events could cause us to change our estimates, which would affect the future calculation of depreciation expense. The range of depreciable lives by asset category is detailed in Note 7—Property, Plant and

Equipment.

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

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

Asset Retirement Obligation. We record the fair value of a liability related to the retirement of long-lived assets at the time we incur a legal obligation if the liability can be reasonably estimated. When we initially record the liability, we increase the carrying amount of the related asset by the amount of the liability. Over time, we accrete the liability to its future value and record the accretion amount to operating expense.

Our operating assets generally consist of underground petroleum products pipelines, crude pipelines and related components along rights-of-way and above ground storage tanks and related facilities. Our right-of-way agreements typically do not require the dismantling, removal and reclamation of the right-of-way upon permanent removal of the pipelines and related facilities from service. Additionally, management is unable to predict when, or if, our pipelines, storage tanks and related facilities would become completely obsolete and require decommissioning. Accordingly, except for a $2.4 million liability associated with anticipated tank liner replacements, we have recorded no liability or corresponding asset as an asset retirement obligation as both the amounts and timing of such potential future costs are indeterminable.

Equity Investments. We account for investments greater than 20% in affiliates that we do not control using the equity method of accounting. Under this method, an investment is recorded at our acquisition cost, plus equity in undistributed earnings or losses since acquisition, less distributions received and amortization of excess net investment. Excess net investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. We amortize excess net investment over the weighted-average depreciable asset lives of the equity investee as of the date of the equity investment. Our unamortized excess net investment was $17.1 million and $16.5 million at December 31, 2010 and 2011, respectively. We evaluate equity method investments for impairment annually or whenever events or circumstances indicate that there is an other-than-temporary loss in value of the investment. In the event that we determine that the loss in value of an investment is other-than-temporary, we would record a charge to earnings to adjust the carrying value to fair value. We recognized no equity investment impairments during 2009, 2010 or 2011.

Goodwill and Other Intangible Assets. We do not amortize goodwill, which represents the excess of fair value of the business acquired over the fair value of assets acquired and liabilities assumed. We evaluate goodwill for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. Goodwill was $53.3 million at both December 31, 2010 and 2011. Our reported goodwill at December 31, 2011 included $21.1 million allocated to our petroleum pipeline system segment and $32.2 million allocated to our petroleum terminals segment. During 2011, we changed our purchase price allocation related to our September 2010 acquisition of pipelines and crude oil storage facilities in Texas and Oklahoma (see Note 4–Acquisitions) in which we increased the amount allocated to goodwill and decreased the amount allocated to property, plant and equipment by $13.3 million. These adjustments were made based on our final determination of the fair value of the assets acquired and liabilities assumed in the aforementioned acquisition. We have adjusted the goodwill amount reported as of December 31, 2010 from our previously issued financial statements to reflect this change.

We base our determination of whether goodwill is impaired on management's estimate of the fair value of our reporting units using a discounted future cash flow (“DFCF”) model as compared to their carrying values. Critical assumptions used in our DFCF model included: (i) time horizon of 20 years, (ii) revenue growth of 3.1% and 1.3% per year for our petroleum pipeline system and petroleum terminals, respectively, (iii) expense growth of 4.8% and 4.0% per year for our petroleum pipeline system and petroleum terminals, respectively (iv) annual maintenance capital spending growth of 3.0% and (v) 8.5 times earnings before interest, taxes and depreciation and amortization multiple for terminal value. We use October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2009, 2010 or 2011. If impairment were to occur, we would charge the amount of the impairment against earnings in the period in which the impairment occurred. The amount of the impairment would be determined by subtracting the implied fair value of the reporting unit goodwill from the carrying amount of the goodwill.

Judgments and assumptions are inherent in management's estimates used to determine the fair value of our operating segments and are consistent with what management believes would be utilized by the primary market participant. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in our financial statements.

We amortize other intangible assets over their estimated useful lives of 4 years up to 25 years. The weighted-average asset life of our other intangible assets at December 31, 2011 was approximately 6 years. We adjust the useful lives if events or circumstances indicate there has been a change in the remaining useful lives. We review our other intangible assets for impairment whenever events or changes in circumstances indicate we should assess the recoverability of the carrying amount of the intangible asset. We recognized no impairments for other intangible assets in 2009, 2010 and 2011. Amortization of other intangible assets was $1.7 million, $2.0 million and $2.8 million in 2009, 2010 and 2011, respectively, of which $0.6 million was charged against transportation and terminals revenues in each year during 2010 and 2011.

Tank Bottom Inventory. A contract we have with a customer at our crude oil terminal in Cushing, Oklahoma requires us to maintain a minimum volume of crude oil in the tanks they utilize at that facility. Because of this contractual requirement, the crude oil we own at that facility is not sold in the normal course of our business; therefore, we classify these crude oil barrels as a long-term asset carried at cost adjusted for gains or losses on certain derivative contracts as described below. In any subsequently negotiated lease agreements for this storage at this facility, management could decide to require the lease customer(s) to carry their own tank bottom inventory, in which case, we would sell our existing tank bottom inventory. At December 31, 2011, our tank bottom inventory consisted of 0.7 million barrels of crude oil with a carrying value of $59.5 million. We have entered into New York Mercantile Exchange ("NYMEX") contracts representing 0.7 million barrels of crude oil, which we have designated as fair value hedges against price changes in our tank bottom inventory. The fair value of these derivative agreements as of December 31, 2010 and 2011 was a loss of $4.9 million and $6.4 million, respectively, which was recorded as an increase to the tank bottom inventory and an increase to the noncurrent derivative liability.

Assets Held for Sale. We classify long-lived assets to be disposed of through sales that meet specific criteria as held for sale. We cease depreciating those assets effective on the date the asset is classified as held for sale. We record those assets at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change. We had no assets classified as held for sale during 2009 and 2010. In October 2011, based on a plan for the potential sale of the ammonia pipeline system, we classified this asset as held for sale. As of December 31, 2011, the ammonia pipeline system no longer met the criteria as a held for sale asset; therefore, we reclassified this asset as held and used. The adjustments to the carrying amount of the ammonia pipeline system due to its reclassification as held and used were insignificant.

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

Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the financial statements.
There were no impairments recorded in 2009 and 2010 and impairments recognized during 2011 were insignificant.

Debt Placement Costs. We capitalize costs incurred for debt borrowings when paid and amortize those costs over the life of the associated debt instrument using the effective interest method. When debt is retired before its scheduled maturity date, we write off any remaining placement costs associated with that debt.

Interest Capitalized. During construction, we capitalize interest on all construction projects requiring a completion period of three months or longer and total project costs exceeding $0.5 million, based on the weighted-average interest rate of our debt.

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

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

Paid-Time Off Benefits. We recognize liabilities for paid-time off benefits when earned. Paid-time off liabilities were $11.1 million and $11.9 million at December 31, 2010 and 2011, respectively. These balances represented the remaining vested paid-time off benefits of employees. We reflect liabilities for paid-time off in the payroll and benefits balances of the accompanying consolidated balance sheets.

Derivative Financial Instruments. We record derivative instruments on our balance sheets at fair value as either assets or liabilities. We designate and account for derivatives that qualify as normal purchases and sales using traditional accrual accounting.

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

As part of our risk management process, we assess the creditworthiness of the financial and other institutions with which we execute financial derivatives. We use, or have used, derivative agreements primarily for fair value hedges of our debt, cash flow hedges of forecasted debt transactions and of future purchases and sales of petroleum products. Such financial instruments involve the risk of non-performance by the counterparty, which could result in material losses to us.

We have entered into NYMEX commodity based futures contracts to hedge against price changes on a portion of the petroleum products we expect to sell in the future. Some of these contracts have qualified as cash flow or fair value hedges under ASC 815, Derivatives and Hedging, while others have not. We record the effective portion of the gains or losses for those contracts that qualify as cash flow hedges in other comprehensive income and the ineffective portion in product sales revenues. We reclassify gains and losses from contracts that qualify as cash flow hedges from other comprehensive income to product sales revenues when the hedged transaction occurs and we cancel the derivative agreement. We record the effective portion of the gains or losses for those contracts that qualify as fair value hedges as adjustments to the assets or liabilities being hedged and the ineffective portions as adjustments to other income or expense. We recognize the change in fair value of those agreements that are not designated as hedges in product sales revenues, except for those undesignated agreements that economically hedge the inventories associated with our pipeline system overages. We record the change in fair value of those agreements in operating expenses.

We use interest rate derivatives to help manage interest rate risk. We record any ineffectiveness on derivatives designated as hedging instruments and the change in fair value of interest rate derivatives that we do not designate as hedging instruments to other income or expense in our results of operations. For the effective portion of interest rate cash flow hedges, we record the noncurrent portion of unrealized gains or losses as an adjustment to other comprehensive income with the current portion recorded as an adjustment to interest expense. For the effective portion of fair value hedges on long-term debt, we record the noncurrent portion of gains or losses as an adjustment to long-term debt with the current portion recorded as an adjustment to interest expense.

See Comprehensive Income in this Note 2 for details of the derivative gains and losses included in accumulated other comprehensive loss.

Revenue Recognition. We recognize petroleum pipeline and ammonia transportation revenues when shipments are complete. For ammonia shipments and shipments of petroleum products under published tariffs that combine transportation and terminalling services, shipments are complete when customers take possession of their product from our system through tanker trucks, railcars or third-party pipelines. For all other shipments, where terminalling services are not included in the tariff, shipments are complete when the product arrives at the customer-designated delivery point. We recognize injection service fees associated with customer proprietary additives upon injection to the customer's product, which occurs at the time we deliver the product to our customers. We recognize leased tank storage, pipeline capacity leases, terminalling, throughput, ethanol loading and unloading services, laboratory testing, data services, pipeline operation fees and other miscellaneous service-related revenues upon completion of contract services. We recognize product sales upon delivery of the product to the customer. We increase or decrease, as appropriate, product sales for gains and losses associated with the period change in fair value of our NYMEX agreements that we do not designate as hedges, except for those undesignated agreements that economically hedge the inventories associated with our pipeline system overages, and for the ineffective portion of our NYMEX agreements that we designate as cash flow hedges. When the physical sale of hedged petroleum products occurs, we increase or decrease, as appropriate, product sales for the effective portion of the gains and losses of the associated derivative agreement. We record back-to-back purchases and sales of petroleum products where we are acting as an agent to facilitate petroleum product sales between a supplier and a customer on a net basis.

Deferred Transportation Revenues and Costs. Generally, we invoice customers on our petroleum pipeline for transportation services when their product enters our system. At each period end, we record all invoiced amounts associated with products that have not yet been delivered (in-transit products) as a deferred liability. Additionally, at each period end we defer the direct costs we have incurred associated with these in-transit products until delivery occurs. We record the net amount of the deferred revenues and costs as a deferred liability. These deferred costs are determined using judgments and assumptions that management considers reasonable.

Pipeline Over/Short Product. The tariffs we charge for our pipeline transportation systems are primarily regulated by the Federal Energy Regulatory Commission (“FERC”); however, certain tariffs are regulated by the Surface Transportation Board or state regulatory authorities. Our tariffs include provisions which allow us to deduct from our customer's inventory a small percentage of the products our customers transport on our pipeline systems. We refer to these product quantities as tender deductions. The purpose of these tender deductions is to help offset the product losses we sustain as a result of shrinkage, evaporation, protection of product quality and product measurement inaccuracies. Each period end, we measure the volume of each type of product in our pipeline system which is compared to the volumes of our shippers' inventories (as adjusted for tender deductions). To the extent that the product volumes in our pipeline system exceeds the volumes of our shippers' book inventories, we increase our product inventories and recognize a gain and to the extent the product in our pipeline system is less than our shippers' book inventories, we record a liability (for product owed to our shippers) and recognize a loss. The product gains and losses we recognize are recorded based on period end product market prices and we include those gains or losses in operating expenses on our consolidated statements of income.

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

Equity-Based Incentive Compensation Awards. The compensation committee of our general partner (the “compensation committee") has approved incentive awards of phantom units representing limited partner interests in us to certain employees. The awards granted include performance-based awards and retention awards. The performance-based awards granted in 2010 contain partial distribution equivalent rights (i.e. distributions in excess of $0.71 per unit) and the performance-based awards granted in 2011 contain full distribution equivalent rights. Other than certain awards granted to our executive officers, the retention awards granted do not contain distribution equivalent rights. Further, the compensation committee has issued phantom units with distribution equivalent rights to our independent directors who have deferred the receipt of board fees into the director deferred compensation plan.

Under ASC 718, Compensation-Stock Compensation, we classify unit awards as either equity or liabilities. Fair value for award grants classified as equity is determined on the grant date of the award, and we recognize this value as compensation expense ratably over the requisite service period, which is the vesting period of each unit award. We calculate the per unit fair value of equity awards as the closing price of our limited partner units on the grant date reduced by the present value of any projected per unit distributions during the requisite service period that will not be paid to the participant. Compensation expense for awards classified as equity is calculated as the number of unit awards classified as equity less estimated forfeitures, multiplied by the per unit grant date fair value of those awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense. We re-measure unit awards classified as liabilities at fair value on the close of business at each reporting period end until settlement date. Fair value at each re-measurement date is the closing price of our limited partner units at each period end reduced by the present value of any projected per unit distributions during the remainder of the requisite service period that will not be paid to the participant. Compensation expense for unit awards classified as liabilities is the number of unit awards classified as liabilities less estimated forfeitures, multiplied by the re-measured fair value of the awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense.

Performance-based awards include provisions that can result in payouts to the recipients from 0% up to 200% of the amount of the award. Additionally, these awards are also subject to personal and other performance components, which could increase or decrease the payout of the number of limited partner units by as much as 20%. Judgments and assumptions of the final award payouts are inherent in the accruals recorded for equity-based incentive compensation costs. The use of alternate judgments and assumptions could result in the recognition of different levels of equity-based incentive compensation costs.

Payouts related to retention awards are based solely on the completion of the requisite service period by the participant. Retention awards contain no provisions which would provide for a payout to the participant of anything other than the original number of units awarded.

The vesting period of the performance-based awards is three years and is generally three years for the retention awards, although certain retention awards with a four-year vesting period have been granted. We use the risk-free interest rate as the discount rate in calculating fair value of the equity and liability awards. We settle vested non-director award grants by issuing new units, except for the associated tax withholding, which we settle by paying with cash on hand. Phantom units issued to our directors, if deferred, are settled in cash in January of the year following their death or resignation from the board.

Contingencies and Environmental. Environmental expenditures are expensed or capitalized based on the nature of the expenditures. We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. We recognize liabilities when environmental costs are probable and we can reasonably estimate those costs. We record environmental liabilities assumed in a business combination at fair value. Otherwise, we record environmental liabilities on an undiscounted basis except for those instances where the amounts and timing of the future payments are fixed or reliably determinable. We use the risk-free interest rate to calculate the present value of discounted environmental liabilities. At December 31, 2011, expected payments on our discounted environmental liabilities were $0.1 million in 2012, $0.1 million in 2013, $0.1 million in 2014, $1.6 million in 2015, $0.1 million in 2016 and $6.8 million for all periods thereafter. We have provided a reconciliation of our undiscounted environmental liabilities to amounts reported on our consolidated balance sheets in the table below (in thousands). See Note 16–Commitments and Contingencies for a discussion of the changes in our environmental liabilities between December 31, 2010 and December 31, 2011.

	December 31,	
	2010	2011
Aggregated undiscounted environmental liabilities	$38,229	$55,012
Amount of discount on environmental liabilities	(5,455)	(5,377)
Environmental liabilities, as reported	$32,774	$49,635

We record environmental liabilities independently of any potential claim for recovery. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account currently available facts, existing technologies and presently enacted laws and regulations. Accruals for environmental matters reflect our prior remediation experience and include an estimate for costs such as fees paid to contractors and outside engineering, consulting and law firms. We maintain selective insurance coverage, which may cover all or portions of certain environmental expenditures. We recognize receivables in cases where we consider the realization of reimbursements of remediation costs as probable. We would sustain losses to the extent of amounts we have recognized as environmental receivables if the counterparties to those transactions were unable to perform their obligations to us.

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

We recognize liabilities for other commitments and contingencies when, after analyzing the available information, we determine it is probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When we can estimate a range of probable loss, we accrue the most likely amount within that range, or if no amount is more likely than another is, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as incurred.

Non-Controlling Owners' Interests of Consolidated Subsidiaries (“non-controlling owners' interest”). At December 31, 2009, there was no non-controlling owners' interest. At December 31, 2010, the non-controlling owners' interest on our balance sheet reflected contributions to MCO by a private investment group less its allocated share of MCO's net losses for the year. In February 2011, we acquired the non-controlling owners' interests in MCO which represented all of the non-controlling owners' interest in subsidiaries on our consolidated balance sheet.

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

The amounts recognized as provision for income taxes in our results of operations reflects a partnership-level tax levied by the state of Texas. This tax is based on revenues less direct costs of sale for our assets apportioned to the state of Texas.

Net Income Per Unit. We calculate basic net income per limited partner unit for each period by dividing the limited partners' allocation of net income by the weighted-average number of limited partner units outstanding. Diluted net income per limited partner unit for each period is the same calculation as basic net income per limited partner unit, except the weighted-average limited partner units outstanding includes the dilutive effect of phantom unit grants associated with our long-term incentive plan. The net income per unit amounts included in these financial statements for 2009 were restated for the reverse unit split that occurred in association with the simplification in 2009.

Comprehensive Income. We account for comprehensive income in accordance with ASC 220, Comprehensive Income. Comprehensive income was determined based on our net income adjusted for changes in other comprehensive income (loss) from our derivative hedging transactions, related amortization of realized gains/losses and adjustments to record our pension and postretirement benefit obligation liabilities at the funded status of the present value of the benefit obligations.

Amounts included in accumulated other comprehensive loss ("AOCL") are as follows (in thousands):

	Derivative Gains (Losses)	Pension and Postretirement Liabilities	Accumulated Other Comprehensive Loss*
Balance, January 1, 2009	$3,653	$(20,771)	$ (17,118)
Net loss on commodity hedges	(6,804)	—	(6,804)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	(164)
Reclassification of net loss on commodity hedges to product sales revenues	5,058	—	5,058
Amortization of net prior service credit and net actuarial loss	—	1,256	1,256
Adjustment to recognize the funded status of postretirement benefit plans	—	9,771	9,771
Balance, December 31, 2009	1,743	(9,744)	(8,001)
Net loss on commodity hedges	(4,283)	—	(4,283)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	