UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

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

Commission file number 1-16335

Magellan Midstream Partners, L.P.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 ☒ No ☐

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

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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the registrant's voting and non-voting limited partner units held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 30, 2010 was $4,972,148,283.

As of February 24, 2011, there were 112,736,571 limited partner units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2011 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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MAGELLAN MIDSTREAM PARTNERS, L.P.

FORM 10-K

PART I

Item 1. *Business*

(a) General Development of Business

We are a Delaware limited partnership formed in August 2000 and our limited partner units are traded on the New York Stock Exchange under the ticker symbol "MMP." Magellan GP, LLC ("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.

Business Acquisition

In September 2010, we acquired an aggregate 7.8 million barrels of crude oil storage in the Cushing, Oklahoma area and more than 100 miles of active petroleum pipelines in the Houston, Texas area from BP Pipelines (North America), Inc. ("BP") for $291.3 million. Additionally, related to this transaction, during October 2010, we acquired certain crude oil working inventory at a fair value of approximately $53.0 million. These assets have improved our connectivity with existing markets as well as expanded our crude oil logistics infrastructure. We have leased a majority of the crude oil storage included in this acquisition to BP for an intermediate period.

(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 refined petroleum products and crude oil. As of December 31, 2010, our asset portfolio consists of:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 51 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

Refined Petroleum Products Industry Background

The United States 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 2010" published by the Energy Information Administration ("EIA"), the Gulf Coast region accounted for approximately 45% of total U.S. daily refining capacity and 76% of U.S. refining capacity expansion from 1999 to 2010. 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.

Crude Oil Logistics Industry Background

The crude oil slate available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties of crude oil. This is due to crude oil grades produced from different producing regions, whether from within or outside the United States, 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 such 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.

Petroleum Products Logistics

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

- *refined petroleum products,* which are the output from refineries and are primarily used as fuels by consumers. Refined petroleum products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil;
- *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; and
- *crude oil and condensate,* which are used as feedstocks by refineries. In addition, we store, blend and distribute biofuels such as ethanol and biodiesel, which are increasingly required by government mandates.

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 51 terminals. The products transported on our pipeline system are largely transportation fuels and, in 2010, were comprised of 54% gasoline, 34% distillates (which include diesel fuels and heating oil), 8% aviation fuel and LPGs and 4% crude oil. Refined product and LPG shipments originate on our pipeline system from direct connections to refineries and interconnections with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end-users. Crude oil shipments originate on our pipeline system from connections to crude oil terminals as well as interconnections with other pipelines for transportation and distribution to refineries.

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

	Year Ended December 31,		
	2008	2009	2010
Percent of consolidated revenues	84%	80%	85%
Percent of consolidated operating margin	79%	75%	79%
Percent of consolidated total assets	68%	73%	70%

See Note 16—*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 December 2010 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 West North Central districts has historically been insufficient to meet the demand for refined petroleum products. 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 region.

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 on the Gulf Coast. 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 upon the production levels and related crude oil demand by Texas City, Texas refineries, predominantly BP's Texas City, Texas refinery. Additional connections for this pipeline are being evaluated that will provide access to a broader group of 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,		
	2008	2009	2010
Shipments (thousand barrels):			
Refined products			
Gasoline	152,703	169,873	194,338
Distillates	114,751	100,214	122,929
Aviation fuel	22,190	19,843	22,612
LPGs	6,252	5,770	4,949
Crude oil	—	—	14,658
Total product shipments	295,896	295,700	359,486
Capacity leases	24,665	29,821	27,084
Total shipments, including capacity leases	320,561	325,521	386,570
Daily average (thousand barrels)	876	892	1,059

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 anticipated demand increases in the markets we serve through expansions or modifications of our petroleum pipeline system, if necessary.

Operations. Our petroleum pipeline system is the longest common carrier pipeline for refined petroleum products and LPGs in the United States. Through direct refinery connections and interconnections with other interstate pipelines, our system can access more than 44% of the refinery capacity in the continental United States. 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, the linefill related to the Houston-to-El Paso pipeline section we acquired in 2009 and petroleum products we transport on this pipeline section 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 in 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, thereby reducing our operating expenses.

In 2010, our petroleum pipeline system generated 72% of its revenue, 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 35 of our pipeline system's 51 terminals. Revenues from terminalling and storage at our other 16 terminals are at privately negotiated rates.

In 2010, 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, 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 Frontier Oil Corporation's refinery in El Dorado, Kansas.

Product revenues for the petroleum pipeline system primarily results 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 specifications 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. 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 markets. Product margin from all of these activities was $114.4 million, $44.2 million and $81.3 million for the years ended December 31, 2008, 2009 and 2010, 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 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.

Commodity Risk Management

Our blending, fractionation and pipeline linefill management activities require us to carry significant levels of inventories. As the volume of petroleum products sales has increased, risk management strategies have become increasingly important in creating and maintaining margins. We use derivative instruments to hedge margins involving our physical assets 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 risk management function has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain other aspects of corporate risk management. Our approved strategies are primarily intended to mitigate and manage price risks that are inherent in our blending, fractionation and pipeline linefill activities. However, not all of our hedges will qualify for hedge accounting treatment given that these contracts are for commodities delivered in the New York harbor, while our physical commodity transactions are generally conducted in the Gulf Coast or mid continent markets in the United States.

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.

Facilities. Our petroleum pipeline system consists of an approximate 9,600-mile pipeline and 51 terminals and includes more than 37 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 2010, approximately 64% of the petroleum products transported on our petroleum pipeline system originated from 13 direct refinery connections and 36% 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 13 refineries shown below:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
BP	Texas City, TX
Coffeyville Resources	Coffeyville, KS
Conoco Phillips	Ponca City, OK
Flint Hills Resources (Koch)	Pine Bend, MN
Frontier Oil	El Dorado, KS
Gary-Williams Energy	Wynnewood, OK
Holly Corporation	Tulsa, OK
St. Paul Park Refining	St. Paul, MN
Murphy Oil USA	Superior, WI
National Cooperative Refining Association	McPherson, KS
Valero Energy	Ardmore, OK
Valero Energy	Houston, TX
Valero Energy	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
Conoco Phillips	Kansas City, KS	Various Gulf Coast refineries (via Seaway/ Standish Pipeline); Borger, TX refinery
Explorer	Glenpool, OK; Mt. Vernon, MO; Dallas, TX; East Houston, TX; Mt. Pleasant, 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	Various OK & KS refineries and Mandan, ND refinery
ONEOK Partners	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Sinco	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

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 who, 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 who 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 supplemental agreements with shippers that commonly result in volume and/or term commitments by shippers in exchange for reduced tariff rates or capital expansion commitments on our part. For 2010, approximately 54% of the shipments on our pipeline system were subject to these supplemental agreements . 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, 2010, 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, 2010 represented 42% of total revenues for our petroleum pipeline system and 59% 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 arrangements, 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 average transportation rate 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. Ethanol producers are responding to these mandates by significantly increasing their capacity for production of 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 systems. 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 storage terminals are large storage and distribution facilities that in many cases have marine access and in some cases are in close proximity to large refining complexes. Our crude storage terminal is located in Cushing, Oklahoma, one of the largest crude oil trading hubs in the United States. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as those operated by Colonial, Explorer, Plantation and TEPPCO. 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,		
	2008	2009	2010
Percent of consolidated revenues	14%	18%	14%
Percent of consolidated operating margin	19%	23%	22%
Percent of consolidated total assets	28%	25%	28%

See Note 16—*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 and a crude oil storage terminal in Cushing, Oklahoma. Our storage terminals have an aggregate storage capacity of approximately 31 million barrels and provide distribution, storage, blending, inventory management and additive injection services for refiners and other large end-users of petroleum products. Our crude oil terminal has an aggregate storage capacity of approximately 8 million barrels.

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 oils, 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 2010, approximately 97% of our storage terminal capacity was utilized. As of December 31, 2010, approximately 95% of our usable storage capacity was under long-term contracts with remaining terms in excess of one year or that renew on an annual basis. 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. 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 United States. 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, Explorer, Plantation or TEPPCO 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 2010, gasoline represented approximately 66% of the product volume distributed through our inland terminals, with the remaining 34% 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. Due to the increasing use of renewable fuels in the Southeast, we have added ethanol blending capabilities at most of our inland terminals.

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 contracts with customers that typically last for one year with a provision that, at the end of each contract's term, automatically renews the contract for another one-year period unless we or our customer provide written notice to cancel the contract. A number of these contracts contain a minimum throughput provision that obligate the customer to move a minimum amount of product through our terminals or pay for terminal capacity reserved but not used. 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,		
	2008	**2009**	**2010**
Percent of consolidated revenues	2%	2%	1%
Percent of consolidated operating margin	2%	1%	(1)%
Percent of consolidated total assets	1%	1%	1%

See Note 16—*Segment Disclosures* in the accompanying consolidated financial statements for additional financial information about the ammonia pipeline system segment.

Operations. We generate more than 90% of 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 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, 2010 through June 30, 2011 are 550,000 tons.

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 2008, 2009 or 2010. 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. If these customers were unable to purchase petroleum products from us, we believe that other companies would purchase the products from us.

	Year Ended December 31,		
	2008	**2009**	**2010**
Customer A	12%	5%	13%
Customer B	12%	11%	11%
Total	24%	16%	24%

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 "just and reasonable" and nondiscriminatory. Rates of interstate oil pipeline companies, like some of those charged for our petroleum pipeline system, are currently regulated by FERC primarily through an index methodology, which for the five-year period ending July 2010, was set at the change in the producer price index for finished goods ("PPI-FG") plus 1.3%. In December 2010, the FERC established a new price index of PPI-FG plus 2.65% for the five-year period beginning July 1, 2011. Certain shippers have requested a rehearing of this matter by the FERC and other shippers have asked a U.S. court of appeals to review FERC's decision. At this time, management is unable to determine whether the FERC will rehear this matter or whether the court of appeals will review it or what outcome might result should such rehearing or court review occur.

Under the indexing regulations, a pipeline can request a rate increase that exceeds index levels for indexed rates using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rate resulting from application of the FERC index. Approximately 40% of our petroleum pipeline system is subject to this indexing methodology. In addition to rate indexing and cost-of-service filings, 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 60% 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.

In May 2005, the FERC adopted a policy statement indicating it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect actual or potential tax liability attributable to their public utility income, regardless of the form of ownership.

Pursuant to this policy statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. This tax allowance policy was upheld by the D.C. Circuit in May 2007. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although this policy is generally favorable for pipelines that are organized as pass-through entities such as a partnership, it still entails rate risk due to the case-by-case review requirement.

The Surface Transportation Board ("STB"), a part of the United States 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 regulation with respect to such intrastate transportation by state regulatory authorities in the states of Colorado, Illinois, Kansas, Minnesota, Oklahoma and Texas. However, in most instances, the state commissions have not initiated investigations of the rates or practices of petroleum pipelines.

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

Market Manipulation Regulations

Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 ("EISA") and regulations by the Federal Trade Commission ("FTC") with respect to trading and market manipulation. The Commodity Futures Trading Commission (the "CFTC") has similar authority over commodities trading and futures contracts pursuant to the Commodity Exchange Act. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation. In addition, our rates for interstate pipeline transportation services are regulated by the FERC under the Interstate Commerce Act ("ICA"). Should we violate anti-manipulation laws and regulations or the ICA and FERC's regulations under the ICA, we could also be subject to disgorgement of profits or the payment of refunds and to recommended criminal penalties. Should we violate these laws and regulations, we could also be subject to related third-party damage claims.

Additional proposals and proceedings that might affect the petroleum industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our operations. We do not believe that we would be affected by any such FERC action materially different than similarly situated companies.

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 providing an employment workplace that is free from recognized hazards. 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 as well as 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 have the potential to have a material adverse effect on our results of operations, financial position and cash flow.

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $34.4 million and $32.8 million at December 31, 2009 and December 31, 2010, 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 $3.9 million and $2.2 million at December 31, 2009 and December 31, 2010, respectively.

Environmental Insurance Policies. We have insurance policies which 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 on the majority of our petroleum pipeline system that have various terms, with most expiring between 2014 and 2017.

Clean Air Act. Our operations are subject to the federal Clean Air Act ("CAA"), as amended, 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.

Petroleum Products Blending Review. As a result of an internal operational review of our petroleum products blending activity, we have disclosed instances of regulatory non-compliance to the Environmental Protection Agency ("EPA"). We have not received a response from the EPA on this matter and management believes that this situation will not result in the imposition of material fines or penalties on us by the EPA.

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 will 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 will be 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, recordkeeping and protection of chemical-terrorism vulnerability information.

DHS has determined that one of our facilities storing butane met 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, 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 also 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 the Superfund law, 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 significant.

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 ("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 shorelines or in the exclusive economic zone of the United States. 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 the costs of non-compliance and damages. 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. Consequently, the EPA proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

Further, Congress has actively 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 United States emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. Future laws might require reduction in greenhouse gas emissions by 2020 with a further reduction of such emissions by 2050. Allowances under a future cap-and-trade program would be expected to significantly escalate in cost over time. The net effect of such potential legislature would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. 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 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 United States Department of Transportation under the Hazardous Liquid Pipeline Safety Act ("HLPSA") of 1979, as amended, 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 United States 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 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.

Changes to federal pipeline safety laws and regulations are being considered by Congress and the Pipeline Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation ("DOT"). Legislation requiring more stringent regulation was passed by the U.S. House of Representatives in 2010 but was not put to a vote in the U.S. Senate. Similar legislation is expected to be considered in the current session of Congress. The DOT has proposed legislation providing for more stringent oversight of pipelines and increased penalties. PHMSA has also announced an intention to strengthen its rules and regulations. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service due to more stringent and comprehensive safety regulation and higher penalties for violations of those regulations.

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 that arise before February 2016 and title defects related to the portion of our petroleum pipeline system acquired in April 2002 that arise before April 2012. 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, 2010, we had 1,271 employees. At December 31, 2010, the labor force of 542 employees assigned to our petroleum pipeline system was concentrated in the central United States. Approximately 39% of these employees were represented by the United Steel Workers Union ("USW"). Our collective bargaining agreement with the USW expires January 31, 2012. The labor force of 284 employees assigned to our petroleum terminals operations at December 31, 2010 was primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 9% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2013. At December 31, 2010, the labor force of 20 employees assigned to our ammonia pipeline system was concentrated in the central United States. None of these employees was 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 United States. See Note 16—*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 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 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 pipeline and terminals could result in a significant reduction in the volume of products that we transport, store and distribute, and thereby reduce our cash flow and our ability to pay cash distributions. Economic conditions worldwide have from time to time resulted in reduced demand for the products transported and stored by our pipelines and terminals and 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 entire United States 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 market demand include:

- an increase in the market prices of crude oil and petroleum products, which may reduce demand for crude oil, gasoline and other petroleum products. 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; 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 at substantially lower rates at our storage terminals and at 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, 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 crude oil or refined products, which could adversely affect the demand for our storage services.

We have constructed and continue to construct 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 crude oil and petroleum products. If the prices of crude oil and 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 reduce the amount of cash we generate.

Fluctuations in prices of petroleum products, LPGs and crude oil 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 pipeline 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 refined petroleum products and crude oil 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 or crude oil could result in significant unrealized gains or losses on transactions we enter to hedge our commodity exposure. 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 refined products and crude oil by utilizing physical purchase and sale agreements, futures contracts traded on the NYMEX, options 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 and crude oil purchase and sale activities by utilizing physical purchase and sale agreements, futures contracts traded on the NYMEX, options 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. In addition, 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. Finally, 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 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. Nevertheless, 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 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 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, 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, and 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 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 on our petroleum pipeline system. Shippers may protest our pipeline tariff filings, and the FERC may investigate new or changed 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. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC may also investigate tariff rates absent shipper complaint. If existing rates challenged by complaint 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, the FERC could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

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 40% 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. For the five-year period ending June 30, 2011, the indexing method required a pipeline to change its rates by a percentage equal to the change in the PPI-FG plus 1.3%. 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. Certain shippers have requested a rehearing of this matter by the FERC and other shippers have asked a U.S. court of appeals to review FERC's decision. At this time, management is unable to determine whether the FERC will rehear this matter or whether the court of appeals will review it or what outcome might result should such rehearing or court review occur. 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 60% 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 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 40% of the markets served by our petroleum pipeline system. For the five-year period ending June 30, 2011, the indexing method provided for a pipeline to change its rates by a percentage equal to the change in the PPI-FG plus 1.3%

and for the five-year period beginning July 1, 2011, the indexing method provides for changes in rates by a percentage equal to the change in the PPI-FG plus 2.65%. Certain shippers have requested a rehearing of this matter by the FERC. At this time, management is unable to determine whether the FERC will rehear this matter or what outcome might result should such rehearing occur. 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/or 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 adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Changes in federal, state and local laws and regulations that govern the environmental and operational safety aspects of our operations could increase our costs and liabilities.

Each of our operating segments is subject to the risk of incurring substantial costs and liabilities under environmental and safety laws and regulations. These costs and liabilities arise under increasingly stringent environmental and safety laws, including regulations and governmental enforcement policies, and as a result of claims for damages to property or persons arising from our operations. Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens and, to a lesser extent, issuance of injunctions to limit or cease operations. If we were unable to recover these costs through increased revenues, our ability to meet our financial obligations and pay cash distributions could be adversely affected.

The terminal and pipeline facilities that comprise our petroleum pipeline system have been used for many years to transport, distribute or store 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.

Further, the transportation of hazardous materials in our pipelines may result in environmental damage, including accidental releases that may cause death or injuries to humans, third-party damage, natural resource damages and/or result in federal and/or state civil and/or criminal penalties that could be material to our results of operations and cash flows.

Anti-market manipulation laws and related regulations could subject us to significant penalties and related third-party damage claims.

We are required to observe anti-market manipulation laws and related regulations enforced by the FTC and CFTC and to comply with FERC rate regulation. The FTC and CFTC hold substantial enforcement authority under the anti-market manipulation laws and regulations, including the ability to assess civil penalties of up to $1 million per day per violation. The FTC, CFTC and FERC also have authority to order disgorgement of profits or refunds and to recommend criminal penalties. Should we violate these laws and regulations, we could also be subject to related third-party damage claims.

Potential regulations under the Dodd-Frank Act regarding derivatives could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law which, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and the entities, such as us, that participate in that market. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission within 360 days from the date of enactment to implement the new legislation. The new legislation, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in commodity prices, and could have an adverse effect on our ability to hedge risks associated with our business. Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations to be adopted by the applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or the resulting rules and regulations may have on our hedging activities.

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 public health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Accordingly, the EPA had proposed two sets of CAA regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, in October 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including sources that emit more than 25,000 tons of greenhouse gases on an annual basis, beginning in 2011 for emissions occurring in 2010. In June 2010, the EPA issued a final rule addressing greenhouse gas emissions in permits for major stationary sources of air emissions, which may ultimately result in emission controls. In November 2010, the EPA adopted a final rule requiring reporting of greenhouse gases from certain oil and gas facilities beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any CAA regulations limiting emissions of greenhouse gases from our equipment and operations or those of customers for whom we transport, store or deliver product, could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for our services.

In addition, Congress has actively 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 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. Future laws might require reduction in greenhouse gas emissions by 2020 with a further reduction of such emissions by 2050. The U.S. Senate has considered similar cap-and-trade legislation, and Congress may consider these or similar legislation. Allowances under a future cap-and-trade program would be expected to escalate significantly in cost over time. The net effect of such potential legislation would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. The Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. 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. It is not possible at this time to predict whether or when Congress will adopt climate change legislation, or how state and federal legal and regulatory initiatives will interact.

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, 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 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 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 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 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 would 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, if any, may affect our business by substantially increasing the level of our indebtedness and liabilities and increasing our risk of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial equity capital or us to incur substantial indebtedness. If we consummate any future acquisitions, 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.

For example, we completed the acquisition of the Houston-to-El Paso pipeline section in July 2009. The purchase price was $252.3 million plus $86.1 million for related linefill inventory. We financed the acquisition with debt, which substantially increased our indebtedness. Subsequently, we have purchased additional inventory to facilitate product shipments on the pipeline. We continue to develop the customer base for this pipeline system, which had minimal commercial activity when we acquired it as a result of the former owner’s 2008 bankruptcy filing, and we anticipate the ramp-up of operations to continue through 2012. During this period, the operating cash flow derived from the assets may be significantly less than we ultimately anticipate once the customer base has been fully developed. As a result, our cash from operations and our credit metrics could be adversely affected during this ramp-up period. In addition, during this period, we will likely continue to own a significant portion of the related linefill inventory, and we could be exposed to price fluctuations in the value of that inventory, or to margin deposits or similar arrangements required by any transactions we enter to hedge the value of that inventory. We cannot assure that the ramp-up period will be limited to one or two years or that we will ever build a customer base for this pipeline system that fully meets our expectations. In addition, we could experience other unanticipated delays in realizing the benefits of the acquisition, or we could discover previously unknown liabilities associated with the acquired assets.

The storage and pipeline assets we acquired from BP depend on facilities owned and operated by others and on a limited number of customers.

The crude oil pipeline system and the refined petroleum pipeline system that we acquired from BP both depend to a substantial degree on the operation of the Texas City, Texas refineries to which those systems are connected, resulting in significant exposure to the performance of the owners of those refineries. In addition, those systems rely on connections to various other pipelines owned and operated by others for supply and distribution of the crude oil and refined petroleum products transported on those systems. Outages at the Texas City, Texas refineries or reduced or interrupted throughput on these connecting pipelines because of weather-related or other natural causes, testing, line repair, damage, reduced operating pressures or other causes could reduce the shipments on the pipeline systems we have acquired, which could adversely affect our cash flows and our ability to pay distributions.

The crude oil storage assets that we acquired from BP in Cushing, Oklahoma have been leased solely by an affiliate of the seller of those assets, and we are subject to risks of loss from nonpayment by that customer. In addition, any decision by that customer not to renew its lease at the end of the original lease term could result in a reduction of the revenues we receive related to those assets, which could adversely affect our cash flows and our ability to pay distributions.

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 some time 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 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 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 an adverse effect on our results of operations, financial position, cash flows and ability to pay cash distributions.

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

Since the September 11, 2001 terrorist attacks, 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 adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

High natural gas prices can increase ammonia production costs and reduce the amount of ammonia transported through our ammonia pipeline system.

The profitability of our ammonia customers partially depends on the price of natural gas, which is the principal raw material used in the production of ammonia. An extended period of high natural gas prices may cause our customers to produce and ship lower volumes of ammonia, which could adversely affect our cash flows.

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, 2010, we had $1,865.0 million of debt outstanding (excluding unamortized discounts and premiums on debt issuances and the unamortized portion of fair value hedges). Of this amount, borrowings outstanding on our revolving credit facility of approximately $15.0 million were subject to variable interest rates. We also expect to make additional floating-rate borrowings under our revolving credit facility 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 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 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 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, to sell assets or to repay existing debt without penalties. 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.

Our unit purchase rights plan may make it more difficult for others to obtain control of us.

We currently have a unit purchase rights plan, commonly referred to as a “poison pill.” This poison pill will cause substantial dilution to the ownership of a person or group that attempts to acquire us on terms not approved by our general partner’s board of directors and may have the effect of deterring future takeover attempts. The practical effect of a poison pill is to require a party seeking control of us to negotiate with our general partner’s board of directors, which could delay or prevent a change in control of us and the replacement or removal of management. This poison pill, coupled with other anti-takeover provisions in our partnership agreement and under Delaware law, could discourage a future takeover attempt which individual unitholders might deem to be in their best interests or in which unitholders would receive a premium for their limited partner units over current prices.

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 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 the 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. Recently, however, 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 would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year, and could result 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 termination currently would not affect our classification as a partnership for federal income tax purposes. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if the taxpayer requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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*

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

Item 4. *Reserved*

PART II

Item 5. ***Market for Registrant's Limited Partner Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Our limited partner units are listed and traded on the New York Stock Exchange ("NYSE") under the ticker symbol "MMP." At the close of business on February 1, 2011, we had 112,736,571 limited partner units outstanding that were owned by approximately 100,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $43.33 on December 31, 2009 and $56.50 on December 31, 2010. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2009 and 2010 were as follows:

	2009			2010		
Quarter	**High**	**Low**	**Distribution***	**High**	**Low**	**Distribution***
1st	$36.00	$25.36	$0.7100	$47.65	$39.81	$0.7200
2nd	$36.75	$28.93	$0.7100	$48.60	$39.85	$0.7325
3rd	$39.92	$33.75	$0.7100	$51.47	$45.55	$0.7450
4th	$43.70	$36.55	$0.7100	$57.43	$51.45	$0.7575

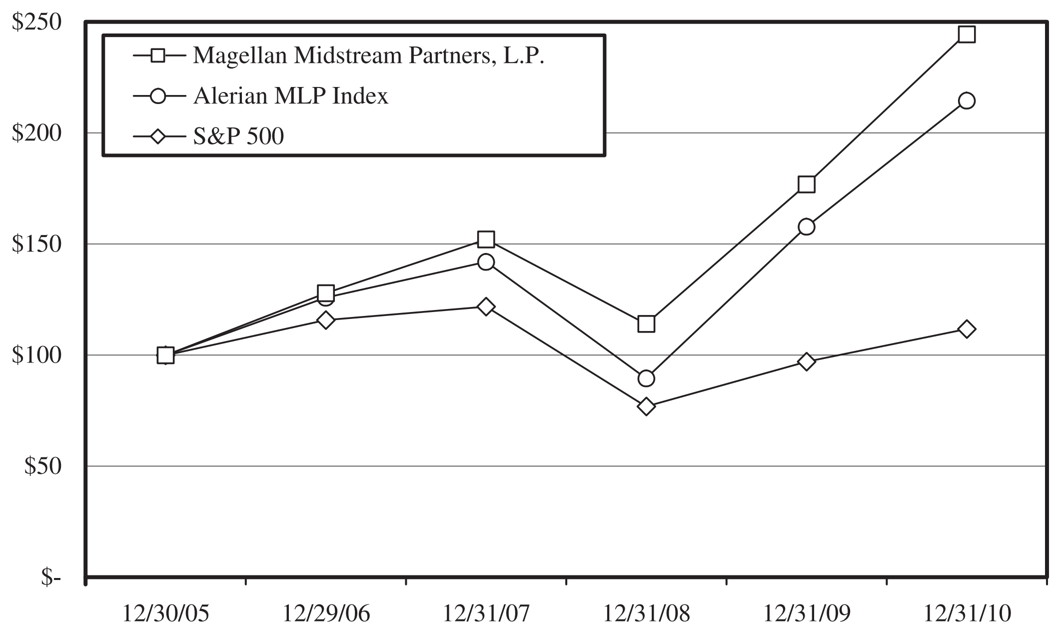
* Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter.

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 $0.7575 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. A portion of the cash we had on hand at December 31, 2010 was restricted (see Note 1–*Organization and Description of Business* in the accompanying financial statements).

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[(1)]. The graph assumes that $100 was invested in our limited partner units and each comparison index beginning on December 30, 2005 and that all distributions or dividends were reinvested on a quarterly basis.

(1) The Alerian MLP Index is a composite of the 50 most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class.



	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
Magellan Midstream Partners, L.P.	$100.0	$128.0	$152.1	$114.1	$176.9	$245.0
Alerian MLP Index	$100.0	$126.1	$142.1	$ 89.6	$158.1	$214.8
S&P 500	$100.0	$115.8	$122.1	$ 77.0	$ 97.3	$111.9

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C or 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 conditions or results of operations. A discussion of our critical accounting estimates and how these estimates could impact future financial conditions 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 which 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 available 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 schedules.

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 table. See Note 16–*Segment Disclosures* in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit. Operating margin is an important measure of the economic performance of our core operations and we believe that investors benefit from having access to the same financial measures utilized by management. Operating profit, alternatively, includes expense items such as 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,				
	2006	2007	2008	2009	2010
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 559,321	$ 608,781	$ 638,810	$ 678,945	$ 793,599
Product sales revenues	664,569	709,564	574,095	334,465	763,090
Affiliate management fee revenues	690	712	733	761	758
Total revenues	1,224,580	1,319,057	1,213,638	1,014,171	1,557,447
Operating expenses	243,860	250,935	264,871	257,635	282,212
Product purchases	605,341	633,909	436,567	280,291	668,585
Gain on assignment of supply agreement	—	—	(26,492)	—	—
Equity earnings	(3,324)	(4,027)	(4,067)	(3,431)	(5,732)
Operating margin	378,703	438,240	542,759	479,676	612,382
Depreciation and amortization expense	76,200	79,140	86,501	97,216	108,668
G&A expense	69,503	74,859	73,302	84,049	95,316
Operating profit	233,000	284,241	382,956	298,411	408,398
Interest expense, net	47,624	47,653	50,479	69,187	93,296
Debt prepayment premium	—	1,984	—	—	—
Debt placement fee amortization	1,925	1,554	767	1,112	1,401
Other (income) expense, net	653	728	(380)	(24)	750
Income before provision for income taxes	182,798	232,322	332,090	228,136	312,951
Provision for income taxes[(a)]	—	1,568	1,987	1,661	1,371
Net income	$ 182,798	$ 230,754	$ 330,103	$ 226,475	$ 311,580
Net income allocation:[(b)]					
Portion applicable to ownership interests before completion of initial public offering[(c)]	$ 5,886	$ —	$ —	$ —	$ —
Non-controlling owners' interest	148,292	175,356	244,430	99,729	(397)
Limited partner interests	33,069	61,580	87,733	126,746	311,977
General partner interest	(4,449)	(6,182)	(2,060)	—	—
Net income	$ 182,798	$ 230,754	$ 330,103	$ 226,475	$ 311,580
Basic and diluted net income per limited partner unit	$ 0.83	$ 1.55	$ 2.21	$ 2.22	$ 2.85
Balance Sheet Data:					
Working capital (deficit)[(d)]	$ (310,087)	$ (15,609)	$ (29,644)	$ 94,571	$ 109,536
Total assets	2,316,508	2,416,931	2,600,708	3,163,148	3,717,900
Long-term debt[(d)]	518,609	914,536	1,083,485	1,680,004	1,906,148
Owners' equity	1,165,775	1,184,566	1,254,132	1,196,354	1,469,571
Cash Distribution Data:					
Cash distributions declared per MMP unit[(e)]	$ 2.34	$ 2.55	$ 2.77	$ 2.84	$ 2.96
Cash distributions paid per MMP unit[(e)]	$ 2.29	$ 2.49	$ 2.72	$ 2.84	$ 2.91

	Year Ended December 31,				
	2006	2007	2008	2009	2010
	(in thousands, except per unit amounts and operating statistics)				
Other Data:					
Operating margin (loss):					
Petroleum pipeline system	$287,574	$354,914	$428,903	$361,598	$480,781
Petroleum terminals	84,992	83,289	101,713	110,573	132,748
Ammonia pipeline system	2,554	(2,995)	8,660	3,666	(4,156)
Allocated partnership depreciation costs[f]	3,583	3,032	3,483	3,839	3,009
Operating margin	$378,703	$438,240	$542,759	$479,676	$612,382
Distributable cash flow:					
Net income	$182,798	$230,754	$330,103	$226,475	$311,580
Depreciation and amortization expense[g]	78,125	80,694	87,268	98,328	110,069
Equity-based incentive compensation expense[h]	10,820	6,213	931	6,123	15,499
Asset retirements and impairments	8,031	8,548	7,180	5,529	1,062
Commodity-related adjustments:					
NYMEX losses (gains) recognized in the current period associated with products that will be sold in the future[i]	—	—	(20,200)	10,475	14,945
NYMEX losses (gains) recognized in previous periods associated with products that were sold in the current period[j]	—	—	—	20,200	(7,675)
Lower-of-cost-or-market adjustments	—	—	6,413	(6,413)	—
Houston-to-El Paso cost of sales adjustment[k]	—	—	—	—	478
Maintenance capital	(26,160)	(31,243)	(43,232)	(37,999)	(44,620)
Expenses paid by (credited to) a former affiliate[l]	13,652	10,617	(4,344)	5,144	—
Product supply agreement gains[m]	(2,563)	(2,563)	(26,919)	—	—
Other	(6,960)	(4,876)	1,013	541	(1,579)
Distributable cash flow	$257,743	$298,144	$338,213	$328,403	$399,759
Operating Statistics:					
Petroleum pipeline system:					
Transportation revenue per barrel shipped	$ 1.060	$ 1.147	$ 1.193	$ 1.205	$ 1.160
Volume shipped (million barrels)[n]	309.6	307.2	295.9	295.7	359.5
Petroleum terminals:					
Storage terminal (formerly marine terminal) average utilization (million barrels per month)	18.9	19.9	21.4	23.5	25.8
Inland terminal throughput (million barrels)	110.1	117.3	108.1	109.8	114.7
Ammonia pipeline system:					
Volume shipped (thousand tons)	726	716	822	643	462

(a) Beginning in 2007, the state of Texas implemented a partnership-level tax based on a percentage of net revenues apportioned to the state of Texas. The estimate of this tax was reported as provision for income taxes on the consolidated statements of income included in this report.

(b) 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 in 2010, which was partially owned by a private investment group.

(c) Prior to the simplification of our capital structure in September 2009, these financial statements were those of Holdings, which at that time was the owner of our general partner. As our general partner, Holdings fully consolidated our financial results. Holdings was taken public in February 2006. This represents income allocable to the owners of Holdings prior to its initial public offering in February 2006.

(d) The maturity date of our pipeline notes was October 7, 2007. As a result, the $270.8 million carrying value of these notes was classified as a current liability on the December 31, 2006 consolidated balance sheet. This debt was refinanced before its maturity.

(e) 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.

(f) 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.

(g) Includes debt placement fee amortization.

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

(i) 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.

(j) When we physically sell products that we have economically hedged (but did not qualify for hedge accounting treatment), we include in our DCF calculations the full amount of the change in fair value of the associated derivative agreement.

(k) 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 distributable cash flow purposes rather than average inventory costing as used to determine our results of operations.

(l) 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 general and administrative costs above specified amounts and (ii) certain environmental costs that were subject to an environmental indemnification settlement in 2004. In addition, our general and administrative 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.

(m) 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 distributable cash flow 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 eliminated from our distributable cash flow calculations.

(n) Excludes capacity leases.

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

Introduction

We are a publicly traded limited partnership 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 and crude oil. As of December 31, 2010, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 51 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

Beginning in 2010, our East Houston, Texas terminal was transferred from our petroleum terminals segment to our petroleum pipeline system segment due to its increasing usage as a pipeline terminal. Since the beginning of 2010, this facility has been under petroleum pipeline management and its operating results have been reported as part of that segment. As a result, historical financial results for our segments have been adjusted to conform to the current period's presentation. This historical reclassification did not materially impact segment financial results and did not change consolidated financial results.

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, 2010.

Recent Developments

Changes in our Executive Officers. Effective February 1, 2011, our chief executive officer, Don R. Wellendorf, retired. The board of directors of our general partner elected Michael N. Mears, formerly our chief operating officer, as chief executive officer and chairman of the board of directors of our general partner. Jeff Selvidge was named senior vice president of Transportation and Terminals effective February 14, 2011, and has assumed a number of the responsibilities formerly performed by Mr. Mears in his role as chief operating officer.

One of our executive officers, Richard A. Olson, senior vice president, operations and technical services, has announced his departure effective March 1, 2011. Larry J. Davied was named senior vice president of Operations and Technical Services effective February 14, 2011, to replace Mr. Olson.

Cash Distribution. On January 27, 2011, the board of directors of our general partner declared a quarterly cash distribution of $0.7575 per unit for the period of October 1, 2010 through December 31, 2010. This quarterly cash distribution was paid on February 14, 2011 to unitholders of record on February 7, 2011. The total distributions paid on 112.7 million limited partner units outstanding was $85.4 million.

Acquisition of Petroleum Storage and Pipelines. On September 1, 2010, we acquired petroleum storage and pipeline assets from BP Pipelines (North America), Inc. ("BP") for $291.3 million. The storage assets acquired consisted of approximately 7.8 million barrels of crude oil storage in Cushing, Oklahoma. In addition, during October 2010, we acquired crude oil working inventories associated with the Cushing crude oil storage assets from BP that had a market value of approximately $53.0 million. The pipeline assets acquired from BP consisted of nearly 40 miles of common carrier crude oil pipelines between Houston and Texas City, Texas and two 35-mile common carrier pipelines that transport refined petroleum products from the Texas City refining region to the Houston, Texas area, including connections to third-party pipelines for delivery to other end-use markets. The acquisition was financed with the proceeds of equity and debt offerings completed during the third quarter of 2010 (see *Equity and Debt Offerings*, below).

Equity and Debt Offerings. In July 2010, we completed a public offering of 5,750,000 of our common units at $46.65 per unit and received net proceeds of approximately $258.4 million after underwriting discounts of $9.5 million and offering expenses of $0.3 million. In August 2010, we issued $300.0 million of 4.25% notes due 2021 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $298.9 million, and net proceeds from this offering, after underwriter discounts of $2.0 million and offering costs of $0.4 million, were $296.5 million. The combined net proceeds from these offerings of $554.9 million were used to pay the $291.3 million purchase price of our acquisition of petroleum storage and pipeline assets from BP in September 2010. We also acquired associated crude oil working inventories that had a market value of approximately $53.0 million in October 2010. The remaining proceeds were used to repay the outstanding balance at that time of $175.5 million on our revolving credit facility and for general partnership purposes.

Magellan Crude Oil, LLC. In May 2010, we formed Magellan Crude Oil, LLC ("MCO"), a Delaware limited liability company, for the purpose of constructing and operating crude oil storage in the Cushing, Oklahoma crude oil hub for lease to third parties. At December 31, 2010, approximately 35% of the common equity of MCO was owned by a private investment group and approximately 65% was owned by us. In addition, we owned all of MCO's cumulative preferred equity. Through December 31, 2010, we have contributed cash of $35.4 million to MCO, of which $9.3 million was recorded as cumulative preferred equity and $26.1 million was recorded as common equity. The private investment group's investment in MCO through December 31, 2010 was $14.3 million. At the time of MCO's formation, we determined that it was not a variable interest entity and subsequently we concluded that it should be consolidated into our results based on our voting and operational control of that entity. Since we consolidate MCO, non-controlling owners' interest in consolidated subsidiaries on our consolidated balance sheet as of December 31, 2010 reflects the contributions to MCO by the private investment group less their allocated share of MCO's net losses for the 2010 fiscal year. The results of MCO have been included in our petroleum terminals segment from the date of its formation. In February 2011, we acquired the private investment group's common equity in MCO for $40.5 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. Expenses resulting from environmental remediation projects include costs from projects relating both to current and past events.

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 United States. In 2010, the pipeline 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, 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 the linefill of the pipeline acquired in the Houston-to-El Paso pipeline section acquisition and we take title to the petroleum products we transport on this pipeline for sale in El Paso, Texas while we build third party volumes on this system. Although our petroleum products blending, fractionation and other commodity-related activities generate significant revenues from the sale of petroleum products, we believe the gross 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 United States. 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 United States. 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.

Acquisitions

We significantly increased our operations during 2010 through the following acquisitions:

- In April 2010, the acquisition of various petroleum products storage tanks already connected to our petroleum pipeline system at Des Moines, Iowa, El Dorado, Kansas and Glenpool and Tulsa, Oklahoma for $29.3 million.
- In September 2010, the acquisition from BP of 7.8 million barrels of crude oil storage in the Cushing, Oklahoma area and more than 100 miles of petroleum pipelines in the Houston, Texas area for $291.3 million.

Growth Projects

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

- strong demand for petroleum products and crude oil storage, 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 enhanced connectivity to key growth markets. We are expanding our crude oil logistics infrastructure in the Cushing, Oklahoma and Houston, Texas markets. The assets acquired from BP will

facilitate our strategy of developing our existing East Houston terminal into a key distribution point for crude oil to Gulf Coast refineries by improving our connectivity within the Houston market and extending our reach to the Texas City refining region.

We spent $549.8 million and $480.1 million on acquisitions and growth projects during 2010 and 2009, respectively. Further, we currently expect to spend approximately $215.0 million in 2011 on projects now underway, with additional spending of approximately $30.0 million thereafter to complete these projects. These expansion capital estimates exclude potential acquisitions or spending on more than $500.0 million of other potential growth projects in earlier stages of development.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") costs, which management does not consider when evaluating the core profitability of our operations. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP.

Year Ended December 31, 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	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)[(a)]	295.7	359.5		
Petroleum terminals:				
Storage terminal (formerly marine 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) 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 recent acquisitions 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 are 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 this year, 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 New York Mercantile Exchange ("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 over the past year.

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 $1.9 billion for 2010 from $1.4 billion for 2009 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 essentially unchanged at 5.4% from 2009 to 2010.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2009

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2008	**2009**	**$ Change**	**% Change**
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$478.5	$494.2	$ 15.7	3 %
Petroleum terminals	138.7	167.0	28.3	20%
Ammonia pipeline system	22.7	19.9	(2.8)	(12)%
Intersegment eliminations	(1.1)	(2.2)	(1.1)	(100)%
Total transportation and terminals revenues	638.8	678.9	40.1	6 %
Affiliate management fee revenues	0.7	0.8	0.1	14%
Operating expenses:				
Petroleum pipeline system	195.3	181.0	14.3	7%
Petroleum terminals	59.1	64.3	(5.2)	(9)%
Ammonia pipeline system	14.1	16.2	(2.1)	(15)%
Intersegment eliminations	(3.7)	(3.9)	0.2	(5)%
Total operating expenses	264.8	257.6	7.2	3%
Product margin:				
Product sales	574.1	334.5	(239.6)	(42)%
Product purchases	436.6	280.3	(156.3)	36%
Product margin	137.5	54.2	(83.3)	(61)%
Gain on assignment of supply agreement	26.5	—	(26.5)	(100)%
Equity earnings	4.1	3.4	(0.7)	(17)%
Operating margin	542.8	479.7	(63.1)	(12)%
Depreciation and amortization expense	86.5	97.2	(10.7)	(12)%
G&A expense	73.3	84.1	(10.8)	(15)%
Operating profit	383.0	298.4	(84.6)	(22)%
Interest expense (net of interest income and interest capitalized)	50.5	69.2	(18.7)	(37)%
Debt placement fee amortization	0.8	1.1	(0.3)	(38)%
Other (income) expense	(0.4)	(0.1)	(0.3)	(75)%
Income before provision for income taxes	332.1	228.2	(103.9)	(31)%
Provision for income taxes	2.0	1.7	0.3	15%
Net income	$330.1	$226.5	$(103.6)	(31)%
Operating Statistics				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.193	$1.205		
Volume shipped (million barrels)[(a)]	295.9	295.7		
Petroleum terminals:				
Storage terminal (formerly marine terminal) average utilization (million barrels per month)	21.4	23.5		
Inland terminal throughput (million barrels)	108.1	109.8		
Ammonia pipeline system:				
Volume shipped (thousand tons)	822	643		

(a) Excludes capacity leases.

Transportation and terminals revenues increased by $40.1 million:

- an increase in petroleum pipeline system revenues of $15.7 million primarily attributable to higher leased storage and transportation revenues and incremental fees for ethanol blending and additives. The higher leased storage revenues resulted from new storage capacity. Transportation revenues increased primarily as a result of higher average tariffs due largely to the mid-year tariff escalations. Otherwise, an increase in gasoline shipments reflecting the impact of lower gasoline prices during 2009 primarily offset lower diesel and aviation fuel shipments resulting from the weak economic conditions in 2009;
- an increase in petroleum terminals revenues of $28.3 million due to higher revenues at both storage and inland terminals. Storage revenues increased primarily at our Galena Park, Texas and Wilmington, Delaware facilities due to leasing new storage tanks placed in service over the 2009 year and higher rates on existing storage. Inland revenues benefitted from higher fees due to ethanol blending and increased throughput volumes; and
- a decrease in ammonia pipeline system revenues of $2.8 million due to lower shipments primarily resulting from operational issues at two of our customers' plants during early 2009 and increased system maintenance and testing during 2009, resulting in the pipeline being unavailable for shipments during that time. The impact of lower volumes on revenues was partially offset by higher average tariffs.

Operating expenses decreased by $7.2 million:

- a decrease in petroleum pipeline system expenses of $14.3 million due primarily to more favorable product overages (which reduce operating expenses) and lower power costs resulting from lower prices for natural gas and electricity, partially offset by higher operating expenses related to the Houston-to-El Paso pipeline section acquisition, which was completed in July 2009, additional compensation costs and higher environmental expenses. The 2008 period included a $12.1 million reduction to environmental expenses resulting from the favorable settlement of a civil penalty related to historical product releases;
- an increase in petroleum terminals expenses of $5.2 million primarily related to higher personnel costs, operating taxes (hurricane damage resulted in lower tax assessments in 2008) and gains recognized from insurance proceeds received in 2008 associated with hurricane damages sustained during 2005; and
- an increase in ammonia pipeline system expenses of $2.1 million due primarily to an increase in system maintenance and testing in 2009.

Product sales revenues primarily resulted from our petroleum products blending activities, product marketing and linefill management associated with the Houston-to-El Paso pipeline section acquisition, terminal product gains and transmix fractionation. Product margin decreased $83.3 million primarily because the unrealized losses on NYMEX contracts during 2009 compared unfavorably to the unrealized gains experienced during 2008 by $48.7 million. Otherwise, product margin decreased $34.6 million primarily reflecting lower fractionation margins and lower margins from the sale of product overages at our petroleum terminals. The lower product margins and the change in the value of the NYMEX contracts resulted primarily from significantly lower product prices in 2009 compared to 2008.

The 2008 period benefited from a $26.5 million non-cash gain on the assignment of a third-party supply agreement during March 2008. The gain resulted from the write-off of the unamortized amount of a liability we recognized related to the fair value of the agreement, which we assumed as part of our acquisition of certain pipeline assets in October 2004.

Depreciation and amortization expense increased by $10.7 million primarily due to expansion capital projects and acquisitions in 2009.

G&A expense increased by $10.8 million between periods primarily due to higher personnel costs and equity-based incentive compensation costs. Personnel costs were higher due to additional headcount, merit increases and substantially higher bonus accruals. Equity-based incentive compensation costs increased primarily because the expense associated with the final tranche of the 2007 unit awards was recognized over a shorter period than in previous years and because our limited partner unit price increased 43% during 2009.

Interest expense, net of interest income and interest capitalized, increased $18.7 million in 2009. Our average debt outstanding increased to $1.4 billion for 2009 from $1.0 billion for 2008 principally due to borrowings for expansion capital expenditures and the Houston-to-El Paso pipeline section acquisition. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 5.4% in 2009 from 5.7% in 2008.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $434.9 million, $269.4 million and $424.7 million for the years ended December 31, 2008, 2009 and 2010, respectively.

- 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.
- The $165.5 million decrease from 2008 to 2009 was primarily attributable to:
  - a $54.3 million decrease in net income, excluding the increase in non-cash depreciation and amortization expense, the $26.5 million non-cash gain on assignment of a third-party supply

agreement in 2008 and the $12.1 million non-cash reduction to operating expenses resulting from the 2008 favorable settlement of a civil penalty related to historical product releases on our petroleum pipeline system;

- a $131.8 million decrease resulting from a $59.1 million increase in inventory in 2009 versus a $72.7 million decrease in inventory in 2008. The increase in inventory during 2009 is primarily attributable to the linefill inventory related to our Houston-to-El Paso pipeline section acquisition in 2009. The decrease in inventory during 2008 is principally due to the sale of petroleum products inventory when we assigned our product supply agreement to a third party in March 2008 as well as a significant decrease in product prices during the latter part of 2008; and
- a $56.2 million decrease resulting from a $31.9 million increase in trade accounts receivable and other accounts receivable in 2009 versus a $24.3 million decrease in trade accounts receivable and other accounts receivable in 2008. The increase during 2009 is primarily due to an increase in product prices during late 2009 and timing of payments from our customers. The decrease during 2008 is primarily due to a significant decrease in product prices during the latter part of 2008.

These decreases were partially offset by:

- a $32.3 million increase resulting from a $12.9 million increase in accrued product purchases in 2009 versus a $19.4 million decrease in accrued product purchases in 2008 due primarily to the timing of invoices received from suppliers;
- as a result of the assignment of our product supply agreement to a third party in March 2008, we refunded a deposit to our customer, reducing cash in 2008 by $18.5 million;
- a $10.1 million increase resulting from an $8.4 million increase in accrued payroll and benefits in 2009 versus a $1.7 million decrease in accrued payroll and benefits in 2008 due primarily to higher accrued employee incentive compensation in 2009; and
- a $9.9 million increase resulting from a $17.8 million increase in accrued interest payable in 2009 versus a $7.9 million increase in accrued interest payable in 2008 due primarily to the issuance of $550.0 million of long-term notes during 2009.

Net cash used by investing activities for the years ended December 31, 2008, 2009 and 2010 was $304.7 million, $604.9 million and $590.2 million, respectively. 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. Furthermore, proceeds from the sale of assets during 2010 were $8.3 million, including $3.0 million of proceeds from the settlement of our insurance claim related to a tank fire at one of our petroleum pipeline system terminals and $3.0 million of proceeds from our insurance carrier related to damages incurred from Hurricane Ike at one of our petroleum terminals. 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. These acquisitions were reported collectively as acquisitions of businesses. Additionally, capital expenditures in 2009 were $216.7 million, which included $43.3 million for maintenance capital and $173.4 million for expansion capital. Significant expansion capital expenditures during 2009 included new storage tanks at our Wilmington, Delaware and Galena Park, Texas terminals. During 2008, we spent $272.1 million for capital expenditures, which included $46.9 million for maintenance capital and $225.2 million for expansion capital. Additionally, we acquired petroleum products terminals in Iowa and Minnesota and a petroleum products terminal in Texas along with a 76-mile petroleum products pipeline, collectively, for $38.3 million plus related liabilities assumed of $2.6 million.

Net cash provided (used) by financing activities for the years ended December 31, 2008, 2009 and 2010 was $(93.2) million, $301.7 million and $168.8 million, respectively. During 2010, we received net proceeds of

$258.4 million from our public offering of common 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. During 2008, Magellan Midstream Holdings, L.P. ("Holdings"), paid distributions of $82.8 million to its unitholders and we paid distributions of $181.5 million to our unitholders other than Holdings. Also during 2008, proceeds from notes issuances of $250.0 million were used to repay $212.0 million of borrowings on our revolving credit facility, with the balance used for general partnership purposes. Net repayments on the revolver during 2008 were $93.5 million.

The quarterly distribution amount related to fourth quarter 2010 was $0.7575 per unit, which was paid in February 2011. If we are able to meet management's targeted distribution growth of 7% during 2011 and the number of outstanding limited partner units remains at 112.7 million, total cash distributions of approximately $350.0 million will be paid to our unitholders in 2011.

In January 2010, the cumulative amounts of the January 2007 equity-based incentive compensation award grants were settled by issuing 140,317 limited partner units and distributing those units to the participants. Associated tax withholdings of $3.4 million and employer taxes of $0.5 million were paid in January 2010.

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, our maintenance capital spending was $45.2 million, including $0.6 million of spending reimbursable by insurance. For 2011, we expect to incur maintenance capital expenditures for our existing businesses of approximately $65.0 million.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. Expenditures for organic growth projects during 2010 were $176.2 million. Including related tank bottom inventory, we further spent $344.3 million to acquire certain assets and working inventory from BP and $29.3 million to acquire petroleum products storage at various locations on our petroleum pipeline system. Based on the progress of expansion projects already underway, we expect to spend approximately $215.0 million of expansion capital during 2011 with an additional $30.0 million in future years 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.

The face value of our debt outstanding as of December 31, 2010 was $1,865.0 million. The difference between the face value and carrying value of the debt outstanding results from the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. At December 31, 2010, maturities of our debt were as follows: $0 in 2011; $15.0 million in 2012; $0 in 2013; $250.0 million in 2014; $0 in 2015; and $1.6 billion thereafter.

Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated notes.

2010 Debt Offering

In August 2010, we issued $300.0 million of 4.25% notes due 2021 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $298.9 million. Net proceeds from this offering, after underwriting discounts of $2.0 million and offering costs of $0.4 million, were $296.5 million. The combined proceeds from this debt offering and our equity offering in July 2010 were used to pay for our acquisition of petroleum storage and pipeline assets from BP and to repay the outstanding balance of the revolving credit facility at that time. The remaining amount of the net proceeds was used for general partnership purposes.

Other Debt

Revolving Credit Facility. As of December 31, 2010, the total borrowing capacity under the revolving credit facility, which matures in September 2012, was $550.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of December 31, 2010, there was $15.0 million outstanding under this facility and $4.6 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets.

6.45% Notes due 2014. In May 2004, we sold $250.0 million aggregate principal of 6.45% notes due 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million.

5.65% Notes due 2016. In October 2004, we issued $250.0 million of 5.65% notes due 2016 in an underwritten public offering. The notes were issued for the discounted price of 99.9%, or $249.7 million. The outstanding principal amount of the notes was increased $3.1 million and $2.6 million at December 31, 2009 and 2010, respectively, for the unamortized portion of a gain realized upon termination of a related interest rate swap.

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. The outstanding principal amount of the notes was increased $10.4 million and $9.1 million at December 31, 2009 and 2010, respectively, for the unamortized portion of gains realized upon termination or discontinuation of hedge accounting treatment of associated interest rate swaps.

6.55% Notes due 2019. In June and August 2009, we issued $550.0 million of 6.55% notes due 2019 in underwritten public offerings. The notes were issued at a net premium of 103.4%, or $568.7 million. In connection with these offerings, we entered into interest rate swap agreements to effectively convert $250.0 million of these notes to floating-rate debt. In May and June 2010, we terminated these interest rate swap agreements. The outstanding principal amount of the notes was decreased by $1.6 million at December 31, 2009 for the fair value less accrued interest of the associated interest rate swap agreements. The outstanding principal amount was increased $15.2 million at December 31, 2010 for the unamortized portion of the gain realized upon termination of the related interest rate swaps.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.40% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million.

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 4.75 to 1.00. 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 for the year ended December 31, 2010.

The revolving credit facility and notes described above are senior indebtedness.

Interest Rate Derivatives. In June and August 2009, we entered into $150.0 million and $100.0 million, respectively, of interest rate swap agreements to hedge against changes in the fair value of a portion of the $550.0 million of 6.55% notes due 2019, and we accounted for these agreements as fair value hedges. These agreements effectively converted $250.0 million of our 6.55% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we received the 6.55% fixed rate of the notes and paid six-month LIBOR in arrears plus 2.18% on $150.0 million of the swaps and 2.34% on the other $100.0 million. In May 2010, we terminated and settled $150.0 million of the swaps and received $9.6 million (excluding $1.8 million of accrued interest). In June 2010, we terminated and settled the remaining $100.0 million of swaps for $6.6 million (excluding $1.5 million of accrued interest). The amounts we received upon termination of these swaps were recorded as adjustments to long-term debt that are being amortized over the remaining life of the 6.55% notes. We had no interest rate swaps outstanding as of December 31, 2010.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2010 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$1,865.0	$ —	$ 15.0	$250.0	$1,600.0
Interest obligations(2)	1,181.5	118.5	236.3	210.0	616.7
Operating lease obligations	20.8	2.4	3.7	1.8	12.9
Pension and postretirement medical obligations	29.4	8.4	3.8	1.3	15.9
Purchase commitments:					
Product purchase commitments(3)	30.5	30.5	—	—	—
Utility purchase commitments	2.2	1.3	0.4	0.2	0.3
Derivative instruments(4)					
Equity-based incentive awards(5)	33.4	13.0	20.4	—	—
Environmental remediation(6)	10.8	3.4	3.3	3.1	1.0
Capital project purchase obligations	49.8	49.8	—	—	—
Maintenance obligations	17.4	15.8	1.6	—	—
Other purchase obligations	3.2	1.6	1.4	0.2	—
Total	$3,244.0	$244.7	$285.9	$466.6	$2,246.8

(1) For purposes of this table, we have assumed that the $15.0 million of borrowings under our revolving credit facility as of December 31, 2010 will not be repaid until the maturity date of the facility in September 2012.
(2) The interest obligation for borrowings under our variable-rate revolving credit facility assumes the borrowings outstanding at December 31, 2010 will remain outstanding until the maturity date of that facility. The interest obligation for borrowings under our variable-rate revolving credit facility further assumes the weighted-average borrowing rate of the facility at December 31, 2010 of 0.7%.
(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 are unable to determine what the amounts, if any, of that commitment might be.
(4) As of December 31, 2010, we had entered into commodity-related derivative contracts representing 2.9 million barrels of petroleum products that we expect to sell in the future. At December 31, 2010, we had recorded a net liability of $16.7 million and made margin deposits of $22.3 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, 2010 fair value of award grants accounted for as liabilities multiplied by the estimated payout percentage of the awards at December 31, 2010, reduced for estimated forfeitures. Settlements of these awards will differ from these reported amounts primarily due to differences between actual and current estimates of payout percentages and forfeitures and for changes in our unit price between December 31, 2010 and the vesting dates of the awards.
(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 ($3.1 million as of December 31, 2010) 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 ($1.5 million) as of December 31, 2010. 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 ($6.2 million as of December 31, 2010) 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.

Other Items

NYMEX Contracts. We use NYMEX contracts as economic hedges against changes in the future price of petroleum products. Some of the NYMEX contracts we entered into qualify as hedges for accounting purposes under Accounting Standards Codification ("ASC") 815-30, *Derivatives and Hedging,* while others have not. Currently, we have three specific groups of commodities that are being hedged with NYMEX contracts:

- Future sales of petroleum products generated from our blending and fractionation activities:
  - > The gains and losses resulting from the mark-to-market changes in value of NYMEX contracts that qualify for hedge accounting treatment are not included in product sales revenues in our consolidated statement of income until the hedged petroleum products are physically sold. During 2010, we recognized $5.4 million of losses associated with derivative agreements that qualified as hedges when the hedged products were sold and the contracts were settled.
  - > As of December 31, 2010, we had open NYMEX contracts for 1.0 million barrels of petroleum products that did not qualify for hedge accounting treatment. We recognize the period change in

fair value of these agreements in our consolidated income statement. These contracts mature between January and July 2011. The cumulative amount of unrealized losses through December 31, 2010 associated with NYMEX agreements that did not qualify for hedge accounting treatment was $6.5 million, which we recorded as a decrease in product sales revenues on our consolidated statements of income and energy commodity derivatives contracts on our consolidated balance sheet. All of the $6.5 million of unrealized losses were recognized in 2010. Additionally, we realized gains of $1.2 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2010.

- Future commodity sales of linefill and working inventory associated with our Houston-to-El Paso pipeline section:
  - At December 31, 2010, we had open NYMEX contracts covering 1.2 million barrels to hedge against changes in the future price of petroleum products associated with the linefill barrels. Contracts covering 0.3 million barrels mature in January 2011 and contracts covering 0.9 million barrels mature in July 2011. Because these NYMEX contracts do not qualify for hedge accounting treatment, we recognize the period change in fair value of these agreements in our consolidated income statement. The cumulative amount of unrealized losses through December 31, 2010 associated with these agreements was $8.7 million, of which $7.8 million of losses were recognized during 2010 and $0.9 million of losses were recognized in the last two quarters of 2009. Additionally, we recognized $3.4 million of losses associated with the linefill NYMEX contracts that were settled during 2010 and were recorded as a decrease in product sales revenues on our consolidated income statement. The linefill and working inventory associated with our Houston-to-El Paso pipeline section are classified as inventory in current assets on our consolidated balance sheets.
- Future commodity sales of linefill and tank bottom inventory associated with our crude pipeline and crude storage activities:
  - During third quarter 2010, we entered into NYMEX contracts hedging less than 0.1 million barrels of linefill in a crude pipeline connected to our Cushing, Oklahoma terminal. As of December 31, 2010, these contracts did not qualify for hedge accounting treatment and mature in March 2011. The unrealized losses of $0.6 million from these agreements during 2010 were recorded as a decrease in product sales revenues on our consolidated income statement. The linefill for our crude pipeline connected to our Cushing terminal is classified as an other current asset on our consolidated balance sheets.
  - During third quarter 2010, we entered into NYMEX contracts to hedge future price changes on 0.7 million barrels of tank bottom inventory. These contracts qualified for and were designated as fair value hedges and mature in November 2013. The unrealized losses of $4.9 million from these agreements during the year were fully offset by an adjustment to the tank bottom inventory and, therefore, there was no impact on product sales revenues. The tank bottom inventory at our Cushing terminal is separately classified as a long-term asset on our consolidated balance sheets.
  - During third quarter 2010, prior to the execution of the cash flow and fair value hedges discussed above, we entered into certain short-term NYMEX contracts as economic hedges of both the linefill and tank bottom inventory discussed above. These short-term contracts were not designated as hedges for accounting purposes. These contracts were terminated and we realized a gain of $0.8 million, which we recorded as an increase in our product sales revenues.

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 and 2010 (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 which 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 which impacted product sales revenues during 2010	$(21.7)

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. Approximately 40% of our tariffs are subject to this indexing methodology while the remaining 60% of the tariffs can be adjusted at our discretion based on competitive factors. The approved methodology used for 2009 and 2010 was the annual change in the producer price index for finished goods ("PPI-FG") plus 1.3%. In December 2010, the FERC approved the indexing methodology to be used for the five-year period beginning in July 2011 of the change in PPI-FG plus 2.65%. Certain shippers have requested a rehearing of this matter by the FERC and other shippers have asked a U.S. court of appeals to review FERC's decision. At this time, management is unable to determine whether the FERC will rehear this matter or whether the court of appeals will review it or what outcome might result should such rehearing or court review occur. Assuming the currently-approved methodology is not changed, based on preliminary estimates of PPI-FG for 2010, we would expect, that for the 40% of our tariffs that are subject to indexing, to increase those tariffs by up to 7% on July 1, 2011.

Unrecognized Product Gains. Our petroleum terminals operations generate product overages and shortages that result from metering inaccuracies, product evaporation or expansion, product releases and product 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 $5.8 million as of December 31, 2010. 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.

Impact of Inflation

Inflation is a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass through increased costs to our customers in the form of higher fees.

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 all three 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 whether or not penalties may be levied by governmental agencies with regard to certain environmental events and, if so, the amounts of such penalties 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. Specifically, our remediation project managers meet once a year with accounting, operations, legal and other personnel to evaluate, in detail, the known environmental sites associated with each of our operating segments. 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 general remediation 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, 2008 were as follows (in millions):

	2009			2010			
Balance 12/31/08	Accruals	Expenditures	Balance 12/31/09	Accruals	Expenditures	Acquisitions	Balance 12/31/10
$41.8	$8.5	$(15.9)	$34.4	$12.9	$(14.9)	$0.4	$32.8

During 2009, we increased our environmental liability accruals by $8.5 million, of which $3.2 million was due to product releases which occurred during 2009 and $5.3 million associated with changes in estimates related to historical releases. At December 31, 2009, we had recognized $3.9 million of receivables from insurance carriers associated with environmental claims.

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.

We based our environmental liabilities at December 31, 2010 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 and operating profit and net income would decrease by approximately $8.2 million, which represents a decrease of 2% and 3%, respectively, of our operating profit and net income for 2010 and basic and diluted net income per limited partner unit would have been reduced by approximately $0.08. Such a change would not materially impact our liabilities or equity. Further, the impact of such an increase 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	$(1,568)	$ 2,467	$(9,067)	$11,314
Expected long-term rate of return on plan assets	(604)	604	—	—
Rate of compensation increase	1,269	(1,009)	4,821	(4,075)
Other postretirement benefits:				
Discount rate	(305)	449	(2,870)	3,668
Assumed health care cost trend rate	613	(449)	3,340	(2,670)

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 over 2008 results and the benefit plans' assets reflect these improvements. While the 2010 and 2009 investment performances were greater than our expected rates of return for these years, 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 2010 actual return on plan assets for our Salaried and USW pension plans was a gain of approximately 11.0% and 11.4%, respectively. Through December 2010, the weighted-average rate of return on pension plan assets for the 7 year period we have controlled the plans was approximately 5.5%, 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 award grants of phantom units to key employees. The majority of the awards granted in 2008, 2009 and 2010 have three-year vesting periods and payouts are primarily based on results relative to a financial metric goal. The financial metric for the 2008, 2009 and 2010 performance awards was distributable cash flow per limited partner unit outstanding excluding the impact of certain commodity-related activities ("adjusted DCF"). 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 metrics being interpolated.

We account for performance awards under ASC No. 718, *Compensation-Stock Compensation*. Under ASC 718, we classify performance awards as either equity or liabilities. Compensation expense for performance awards classified as equity is calculated as the fair value of those unit award grants multiplied by the percentage of the requisite service period completed multiplied by the expected payout percentage less previously-recognized compensation expense. We re-measure liability award grants at fair value on the close of business at the end of each reporting period end until the awards are settled. Compensation expense for performance awards classified as liabilities is calculated as the re-measured fair value of the performance awards multiplied by the percentage of the requisite service period completed 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.

In 2008, management adjusted the expected payout of 2008 performance awards from target levels to 30% primarily because of the extremely poor economic conditions experienced during the year and the unfavorable outlook for future operating results. Equity-based compensation expense for these awards for the year ended December 31, 2008 was $0.5 million. During 2009, because of the downturn in the economic environment the compensation committee adjusted the threshold, target and stretch performance metric goals for the 2008 awards to ensure the motivational and retention features of the awards. Primarily because of these modifications, management adjusted the expected payout percentage in 2009 to 62% and equity-based compensation expense for these awards for the year ended December 31, 2009 increased to $1.8 million. Primarily as a result of: (i) improving economic conditions during 2010; (ii) the strong impact on results of operations from acquisitions completed during the past two years; and (iii) strong base business operating results during 2010, management increased their estimate of the expected payouts of the 2008 performance awards to 120% at March 31, 2010, to 160% at September 30, 2010 and to the actual payout amount of 200% at December 31, 2010. Equity-based compensation expense for these awards for the year ended December 31, 2010 was $10.6 million.

During the 2009 year, 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 the 2010 year, 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.

Valuation of Assets

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

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, Other Intangible Assets and Impairment of Long-Lived Assets

Goodwill. At December 31, 2009 and 2010, we had goodwill of $14.8 million and $39.9 million, respectively. 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 terminal value. 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 our petroleum terminals segment. Based on our assessment, we do not believe our goodwill is impaired, and we did not record a charge associated with ASC 350 during 2008, 2009 or 2010.

Other Intangibles. At December 31, 2009 and 2010, other intangibles net of accumulated amortization were $5.9 million and $13.0 million, respectively. All of the other intangibles we have recognized are assets with finite useful lives. We amortize intangible assets with a finite useful life over the periods we expect the assets to contribute directly or indirectly to our future cash flows. Each reporting period, we evaluate the remaining useful lives of our intangible assets to determine whether events and circumstances warrant a revision to the remaining period of amortization. The primary factors we use to evaluate the estimated useful lives of our intangible assets include: (i) our expected use of the asset, (ii) legal, regulatory and contractual provisions and (iii) the effects of demand, competition and other economic factors. Different estimates or expectations used in our evaluations could result in different useful lives assigned to our intangible assets. The weighted-average amortization period of our intangible assets at December 31, 2010 was approximately 7 years.

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

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

Impairments recorded during 2008 were immaterial, and we recognized no impairments during 2009 or 2010. 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

On February 24, 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 Securities and Exchange Commission ("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 requires 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 are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. Our adoption of the applicable sections of this ASU did not have a material impact on our financial position, results of operations or cash flows.

In August 2009, the FASB issued ASU No. 2009-05, an update to ASC 820-10-35, *Fair Value Measurements*. This ASU provides guidance on measuring the fair value of liabilities. The guidance in this ASU was effective for the first reporting period, including interim periods, beginning after August 28, 2009. Our adoption of this ASU on September 1, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*. The new codification supersedes all existing GAAP standards and became the single source of GAAP authoritative literature, effective for financial statements issued for interim and annual periods ending after September 15, 2009.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events (as amended)*. This Statement requires the disclosure of subsequent events to be distinguished between recognized and non-recognized subsequent events. Further, entities are required to include a description of the period through which subsequent events were evaluated. (Note: ASU No. 2010-09 superseded the requirement to disclose the period through which subsequent events were evaluated for entities who file financial statements with the SEC). Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position ("FSP") No. FAS 107-1 and Accounting Principles Board ("APB") 28-1, *Interim Disclosures About Fair Value of Financial Instruments*. This FSP amended SFAS No. 107 (FASB ASC 825-10) and APB Opinion No. 28: (FASB ASC 270-10) by requiring quarterly as well as annual disclosures of the fair value of all financial instruments. The disclosures are to be in a form that makes it clear whether the fair value and carrying amounts represent assets or liabilities and how the carrying amounts relate to what is reported on the balance sheet. Our adoption of this FSP on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination that Arise from Contingencies*. This FSP amended and clarified FASB Statement No. 141 (revised 2007), *Business Combinations*, to address application issues on the initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP was effective for assets or liabilities arising from contingencies in business combinations that occurred following the start of the first fiscal year that begins on or after December 15, 2008. Our adoption of this FSP 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 are paid a management fee for its operation. We received operating fees from this company of $0.7 million, $0.8 million and $0.8 million in 2008, 2009 and 2010, respectively. These fees were reported as affiliate management fee revenue on our consolidated statements of income.

Prior to the simplification of our capital structure in 2009 (see Note 2—*Summary of Significant Accounting Policies* in the notes to consolidated financial statements for a discussion of the simplification), we paid an affiliate for the direct and indirect G&A expenses our affiliate incurred on our behalf and another affiliate reimbursed us for the expenses in excess of a G&A cap. The amount of G&A costs required to be reimbursed was $1.6 million in 2008. The provisions of the agreements under which we paid an affiliate and were reimbursed by another affiliate for G&A costs expired in 2008.

During 2008, we and Holdings were allocated $0.4 million of non-cash G&A compensation expense, with a corresponding increase in owners' equity, for payments made by an affiliate, MGG Midstream Holdings, L.P., to one of our executive officers.

The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,	
	2008	2009
MGG Midstream Holdings GP, LLC -allocated operating expenses	$84,460	$69,523
MGG Midstream Holdings GP, LLC -allocated G&A expenses	44,482	41,890
MGG Midstream Holdings, L.P.-allocated G&A expenses	440	—

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 Holdings owned our general partner prior to the simplification, Holdings benefited from these distributions. In 2008 and the portion of 2009 prior to the simplification, distributions paid to Holdings by us totaled $85.6 million and $70.4 million, respectively. Until December 2008, certain of our executive officers owned a direct interest of approximately 4% in MGG Midstream Holdings, L.P, which in turn owned limited and general partnership interests in Holdings. Through that ownership interest, those executive officers benefited from our distributions prior to the simplification in September 2009. Following the simplification, Holdings' interests in us, including the interests indirectly held by our executive officers, were converted to limited partner interests and a non-economic general partner interest. As of December 31, 2010, our executive officers owned less than 1% of our limited partner units.

Effective January 31, 2011, Don R. Wellendorf, our former chairman of the board, president and chief executive officer 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 February 1, 2011, to assist in the transition of his duties and responsibilities on an as-needed basis and to provide other advisory and consulting services for consideration of $0.3 million and an agreement that his 2009 and 2010 phantom unit award grants that are performance based, a portion of which would otherwise have been forfeited as a result of his retirement, will not be forfeited. The payout of these awards will continue to be subject to the same financial performance metrics as originally established for 2009 and 2010 award grants. The fair value of these award grants on January 31, 2011 was $1.8 million.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "estimates," "forecasts," "projects," "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 United States;
- 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, 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 United States Surface Transportation Board and state regulatory agencies;
- shut-downs or cutbacks at major refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- weather patterns materially different than historical trends;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards 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 expansion projects or to complete identified expansion projects on time and at projected costs;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- 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 could become subject, including tax withholding issues, safety, 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 and the impact these could have on our unit price;
- 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 product purchases and sales. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2010, 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 $27.7 million, and we had commitments under forward sales contracts for product sales of approximately 0.2 million barrels that are being accounted for as normal sales totaling approximately $25.2 million.

At December 31, 2010, we had open NYMEX contracts used as economic hedges against changes in the price of petroleum products we expect to sell in the future. Some of the NYMEX contracts we have entered into have qualified for hedge accounting treatment under ASC 815-30, *Derivatives and Hedging*, while others have not. At December 31, 2010, the fair value of open NYMEX contracts representing 2.9 million barrels of petroleum products, was a net liability of $16.7 million, of which $11.8 million was recorded as energy commodity derivatives contracts and $4.9 million was recorded as other noncurrent liabilities on our consolidated balance sheet. These open NYMEX contracts mature between January 2011 and November 2013. At December 31, 2010, we had made margin deposits of $22.3 million for these contracts, which was recorded as energy commodity derivatives deposits on our consolidated balance sheet. We have the right to offset the fair value of our open NYMEX contracts against our margin deposits under a master netting arrangement with our counterpart; however, we have elected to separately disclose these amounts on our consolidated balance sheet.

At December 31, 2010, open NYMEX contracts representing 2.2 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 would result in a $2.2 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of these NYMEX contracts would result in a $2.2 million increase in our product sales revenues. The increases or decreases in product sales revenues we recognize from our open NYMEX contracts are substantially offset by higher or lower product sales revenues when the physical sale of the product occurs. However, 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 or may not match the exact specifications of the product being hedged, resulting in hedges that do not eliminate all price risks.

Interest Rate Risk

As of December 31, 2010, we had $15.0 million outstanding on our variable rate revolving credit facility. Considering the amount outstanding on our revolving credit facility as of December 31, 2010, our annual interest expense would change by less than $0.1 million if LIBOR were to change by 0.125%.

Item 8. ***Financial Statements and Supplementary Data***

Management's Annual Report on Internal Control Over Financial Reporting

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

Our assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the business we acquired from BP Pipelines (North America), Inc. (discussed in Note 5—*Acquisitions* to the consolidated financial statements). This acquisition was included in our 2010 consolidated financial statements and constituted $359.4 million and $352.2 million of total and net assets, respectively, as of December 31, 2010 and $18.6 million of revenues for the year then ended.

Management believes that the design and operation of our internal control over financial reporting at December 31, 2010 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, 2010, 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, 2010 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, 2010. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2010, 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, 2010, 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.

As indicated in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the business acquired from BP Pipelines (North America), Inc. (BP)(discussed in Note 5 to the consolidated financial statements), which is included in the 2010 consolidated financial statements of Magellan Midstream Partners, L.P. and constituted $359.4 million and $352.2 million of total and net assets, respectively, as of December 31, 2010 and $18.6 million of revenues for the year then ended. Our audit of internal control over financial reporting of Magellan Midstream Partners, L.P. also did not include an evaluation of the internal control over financial reporting of the acquisition from BP.

In our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the related consolidated statements of income, owners' equity, and cash flows for each of the three years in the period ended December 31, 2010 and our report dated February 25, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2011

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, 2010 and 2009, and the related consolidated statements of income, owners' equity and cash flows for each of the three years in the period ended December 31, 2010. 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 policies 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 25, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2011

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

	Year Ended December 31,		
	2008	**2009**	**2010**
Transportation and terminals revenues	$ 638,810	$ 678,945	$ 793,599
Product sales revenues	574,095	334,465	763,090
Affiliate management fee revenue	733	761	758
Total revenues	1,213,638	1,014,171	1,557,447
Costs and expenses:			
Operating	264,871	257,635	282,212
Product purchases	436,567	280,291	668,585
Depreciation and amortization	86,501	97,216	108,668
General and administrative	73,302	84,049	95,316
Total costs and expenses	861,241	719,191	1,154,781
Gain on assignment of supply agreement	26,492	—	—
Equity earnings	4,067	3,431	5,732
Operating profit	382,956	298,411	408,398
Interest expense	56,764	73,357	96,379
Interest income	(1,482)	(660)	(140)
Interest capitalized	(4,803)	(3,510)	(2,943)
Debt placement fee amortization	767	1,112	1,401
Other (income) expense	(380)	(24)	750
Income before provision for income taxes	332,090	228,136	312,951
Provision for income taxes	1,987	1,661	1,371
Net income	$ 330,103	$ 226,475	$ 311,580
Allocation of net income (loss):			
Noncontrolling owners' interests	$ 244,430	$ 99,729	$ (397)
Limited partners' interest	87,733	126,746	311,977
General partner's interest	(2,060)	—	—
Net income	$ 330,103	$ 226,475	$ 311,580
Basic and diluted net income per limited partner unit	$ 2.21	$ 2.22	$ 2.85
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	39,630	57,115	109,485
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	39,630	57,145	109,561

See notes to consolidated financial statements.

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

	December 31, 2009	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,168	$ 7,483
Restricted cash	—	14,379
Trade accounts receivable (less allowance for doubtful accounts of $139 and $106 at December 31, 2009 and 2010, respectively)	72,978	92,192
Other accounts receivable	8,216	6,175
Inventory	193,001	216,408
Energy commodity derivatives deposits	17,943	22,302
Reimbursable costs	13,280	13,870
Other current assets	14,382	11,774
Total current assets	323,968	384,583
Property, plant and equipment	3,398,606	3,894,610
Less: accumulated depreciation	617,989	716,054
Net property, plant and equipment	2,780,617	3,178,556
Equity investments	22,054	23,728
Long-term receivables	618	1,167
Goodwill	14,766	39,925
Other intangibles (less accumulated amortization of $9,974 and $11,964 at December 31, 2009 and 2010, respectively)	5,896	16,924
Debt placement costs (less accumulated amortization of $4,038 and $5,439 at December 31, 2009 and 2010, respectively)	10,894	11,871
Tank bottom inventory	—	57,937
Other noncurrent assets	4,335	3,209
Total assets	$3,163,148	$3,717,900
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 37,063	$ 41,425
Accrued payroll and benefits	30,300	32,393
Accrued interest payable	32,877	35,799
Accrued taxes other than income	21,261	26,953
Environmental liabilities	11,943	12,202
Deferred revenue	27,776	34,733
Accrued product purchases	36,797	47,324
Energy commodity derivatives contracts	9,257	11,790
Other current liabilities	22,123	32,428
Total current liabilities	229,397	275,047
Long-term debt	1,680,004	1,906,148
Long-term pension and benefits	22,582	28,965
Other noncurrent liabilities	12,317	17,597
Environmental liabilities	22,494	20,572
Commitments and contingencies		
Owners' equity:		
Partners' capital:		
Limited partner unitholders (106,588 units and 112,481 units outstanding at December 31, 2009 and 2010, respectively)	1,204,355	1,466,404
Accumulated other comprehensive loss	(8,001)	(11,096)
Total partners' capital	1,196,354	1,455,308
Non-controlling owners' interests in consolidated subsidiaries	—	14,263
Total owners' equity	1,196,354	1,469,571
Total liabilities and owners' equity	$3,163,148	$3,717,900

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2008	2009	2010
Operating Activities:			
Net income	$ 330,103	$ 226,475	$ 311,580
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	86,501	97,216	108,668
Debt placement fee amortization	767	1,112	1,401
Loss on sale and retirement of assets	7,180	5,529	1,062
Equity earnings	(4,067)	(3,431)	(5,732)
Distributions from equity investments	4,067	3,431	4,853
Equity-based incentive compensation expense	4,751	9,622	18,899
Amortization of net prior service credit and net actuarial loss	(88)	1,256	106
Gain on assignment of supply agreement	(26,492)	—	—
Changes in components of operating assets and liabilities (Note 3)	32,167	(71,773)	(16,181)
Net cash provided by operating activities	434,889	269,437	424,656
Investing Activities:			
Property, plant and equipment:			
Additions to property, plant and equipment	(272,083)	(216,698)	(221,419)
Proceeds from sale of assets	3,862	338	8,300
Changes in accounts payable related to capital expenditures	661	921	(3,432)
Acquisitions of businesses	(38,302)	(390,606)	(291,292)
Acquisition of tank bottom inventory	—	—	(53,017)
Other acquisition	—	—	(29,300)
Distributions in excess of equity investment earnings	1,133	1,127	—
Net cash used by investing activities	(304,729)	(604,918)	(590,160)
Financing Activities:			
Distributions paid	(264,310)	(285,758)	(318,817)
Net borrowings (repayments) under revolver	(93,500)	31,600	(86,600)
Borrowings under long-term notes	249,980	568,699	298,899
Debt placement costs	(2,048)	(4,357)	(2,378)
Net receipt from financial derivatives	10,312	5,335	16,238
Capital contributions by affiliate	3,709	—	—
Increase in outstanding checks	2,671	2,955	2,393
Settlement of tax withholdings on long-term incentive compensation	—	(3,450)	(3,371)
Issuance of common units	—	—	258,407
Capital contributed by non-controlling owners	—	—	4,361
Costs associated with the simplification of capital structure	—	(13,287)	(313)
Net cash (used) provided by financing activities	(93,186)	301,737	168,819
Change in cash and cash equivalents	36,974	(33,744)	3,315
Cash and cash equivalents at beginning of period	938	37,912	4,168
Cash and cash equivalents at end of period	$ 37,912	$ 4,168	$ 7,483
Supplemental non-cash financing activities:			
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	$ 8,536	$ 1,943	$ 2,034
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	General Partner	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Beginning balance, January 1, 2008	$ 44,916	$ 12,505	$ (91)	$ 1,127,236	$1,184,566
Comprehensive income:					
Net income (loss)	87,733	(2,060)	—	244,430	330,103
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	—	(3)	(161)	(164)
Amortization of net prior service credit and net actuarial loss	—	—	(2)	(86)	(88)
Adjustment to recognize the funded status of postretirement plans	—	—	(244)	(12,028)	(12,272)
Total comprehensive income (loss)	87,733	(2,060)	(249)	232,155	317,579
Affiliate capital contributions	—	3,709	—	—	3,709
Distributions	(82,756)	(12)	—	(181,542)	(264,310)
Equity method incentive compensation expense	4,138	—	—	—	4,138
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	—	—	—	8,536	8,536
Acquisition of general partner	14,142	(14,142)	—	—	—
Other	(110)	—	—	24	(86)
Balance, December 31, 2008	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

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

	Partners' Capital				
	Limited Partners	General Partner	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Beginning balance, January 1, 2010	$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	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

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.

In May 2010, we formed Magellan Crude Oil, LLC (“MCO”), a Delaware limited liability company, for the purpose of constructing and operating crude oil storage tanks in Cushing, Oklahoma for lease to third parties. At December 31, 2010, a private investment group owned approximately 35% of the common equity of MCO and we owned approximately 65%. In addition, we owned all of MCO’s cumulative preferred equity. At the time of MCO’s formation, we determined that it was not a variable interest entity and concluded that we should consolidate it into our results based on our voting and operational control of that entity. Since we consolidate MCO, non-controlling owners’ interest in consolidated subsidiaries on our consolidated balance sheet reflects the contributions to MCO by the private investment group less its allocated share of MCO’s net losses for the year. MCO’s cash on hand at December 31, 2010 was $14.4 million, which was unavailable to us for our partnership matters. We have reported this amount as restricted cash on our consolidated balance sheet at December 31, 2010. MCO’s operating results have been included in our petroleum terminals segment from the date of its formation. Through December 31, 2010, we have contributed cash of $35.4 million to MCO. The private investment group’s investment in MCO through December 31, 2010 was $14.3 million, which included cash contributions of $4.4 million, $10.3 million of non-cash contributions, which consisted of $9.1 million of intangible terminalling agreements and $1.2 million of property, plant and equipment and allocated losses of $0.4 million. See Note 23—*Subsequent Events* for a discussion of changes in the ownership of MCO after December 31, 2010.

Description of Business

Petroleum Pipeline System. Our petroleum pipeline system includes approximately 9,600 miles of pipeline and 51 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 and interconnects 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 the Frontier Oil Corporation refinery in El Dorado, Kansas. Our petroleum products blending and fractionation activities are also included in the petroleum pipeline system segment.

During 2010, we acquired nearly 40 miles of common carrier crude oil pipelines between Houston and Texas City, Texas and two 35-mile common carrier pipelines that transport refined petroleum products from the Texas City refining region to the Houston, Texas area, including connections to third-party pipelines for delivery to other end-use markets (see Note 5-*Acquisitions*).

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 United States. 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 United States. 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.

During 2010, we formed MCO for the purpose of constructing and operating crude oil storage in the Cushing, Oklahoma crude oil hub for lease to third parties (see above). Additionally, we acquired approximately 7.8 million barrels of crude oil storage in Cushing, Oklahoma (see Note 5—*Acquisitions*).

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 two less-than-50%-owned investments for which we apply the equity method of accounting. We have eliminated all intersegment transactions.

Simplification. On September 28, 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 (“Holdings GP”) 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.” In these financial statements, we use the term “Partners” to refer to Magellan Midstream Partners, L.P. prior to the simplification, when it is necessary to distinguish that entity. 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 United States (“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.

Regulatory Reporting. Our petroleum pipelines are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), which prescribes certain accounting principles and practices for the annual Form 6 report filed with the FERC that differ from those used in these financial statements. Such differences relate primarily to capitalization of interest, accounting for gains and losses on disposal of property, plant and equipment and other adjustments. We follow GAAP where such differences of accounting principles exist.

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 believe that our credit risk is minimal.

Restricted Cash. Restricted cash includes cash held by MCO to be used for tank construction and is unavailable to us for our partnership matters, including the payment of distributions (see Note 1—*Organization and Description of Business*).

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, crude oil and transmix, which are stated at the lower of average cost or market. During 2008, we recorded a $19.7 million lower-of-cost-or-market adjustment to our transmix inventory associated with our pipeline product overages and shortages. This adjustment was included in operating expenses on the consolidated statement of income included with these financial statements. In addition, during 2008, we recorded lower-of-cost-or-market adjustments of $6.4 million and $3.0 million to our refined petroleum products and transmix inventory, respectively, associated with our petroleum products blending and fractionation activities. 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 FERC approves and regulates the depreciation rates for most of our pipeline assets. We depreciate assets with the same useful lives and similar characteristics using the same rate. The range of depreciable lives by asset category is detailed in Note 8-Property, Plant and Equipment.

When we sell or retire property, plant and equipment, we remove its carrying value and the related accumulated depreciation from our accounts and record any associated gains or losses on our 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 we can reasonably estimate the liability. 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 and ammonia pipelines and related facilities 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 $2.2 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 by 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 $17.8 million and $17.1 million at December 31, 2009 and 2010, 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 2008, 2009 or 2010.

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 $14.8 million and $39.9 million at December 31, 2009 and 2010, respectively. Our reported goodwill at December 31, 2010 included $15.1 million acquired in transactions involving our petroleum pipeline system segment and $24.8 million acquired in transactions involving our petroleum terminals segment.

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 1.5% per year and expense growth of 2.5% per year, except general and administrative ("G&A") costs with an assumed growth of 3.5% per year, (iii) annual maintenance capital spending growth of 2.5% and (iv) 8.5 times earnings before interest, taxes and depreciation and amortization multiple for terminal value. Our DFCF model is further impacted by our weighted average cost of capital. We selected October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2008, 2009 or 2010. 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, 2010 was approximately 7 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 2008, 2009 and 2010. Amortization of other intangible assets was $1.5 million, $1.7 million and $2.0 million in 2008, 2009 and 2010, respectively. Of the $2.0 million of amortization of other intangibles in 2010, $0.6 million was charged against transportation and terminals revenues.

Tank Bottom Inventory. The contract we have with our customer at our crude oil terminal in Cushing, Oklahoma requires us to maintain a minimum volume of crude oil in the tanks at that facility. Because of this contractual requirement, the crude 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. In any subsequently negotiated lease agreements for 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, 2010, our tank bottom inventory consisted of 0.7 million barrels of crude oil with a carrying value of $57.9 million. We have entered into 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 change in fair value of these derivative agreements for the year ended December 31, 2010 was a loss of $4.9 million, which was recorded as an increase to the tank bottom inventory and an increase to the derivative liability.

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.

We classify long-lived assets to be disposed of through sales that meet specific criteria 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 2008, 2009 or 2010.

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.

Impairments recorded during 2008 were insignificant and there were no impairments recorded in 2009 or 2010. The inputs for the valuation models used in determining the fair value of assets impaired during 2008 were Level 3-Significant Unobservable Inputs as described in Accounting Standards Codification ("ASC") 820, *Fair Value Measurements and Disclosures*.

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 $10.2 million and $11.1 million at December 31, 2009 and 2010, 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 account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*, which establishes accounting and reporting standards that require the recording of derivative instruments on the balance sheet at fair value as either assets or liabilities.

For those instruments that qualify for hedge accounting, the accounting treatment depends on their intended use and their designation. We generally 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 recorded in current earnings. The change in fair value of derivative financial instruments that either do not qualify for hedge accounting or are not designated 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 designate and account for derivatives that qualify as normal purchases and sales using traditional accrual accounting. As of December 31, 2010, we had commitments under forward purchase contracts for petroleum product purchases of approximately 0.4 million barrels that will be accounted for as normal purchases totaling approximately $30.1 million, and we had commitments under forward sales contracts for product sales of approximately 0.2 million barrels that will be accounted for as normal sales totaling approximately $25.2 million.

We have also entered into New York Mercantile Exchange ("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 hedges under ASC 815 while others have not. We record the effective portion of the gain or losses for those contracts that qualify as hedge cash flows in other comprehensive income and the ineffective portion in product sales revenues. Each period, we record the change in fair value of those agreements that are not designated as hedges in product sales revenues. We reclassify gains and losses from contracts that qualify as hedges from other comprehensive income to product sales revenues when the hedged transaction occurs and we cancel the derivative agreement.

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 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 and for the ineffective portion of our NYMEX agreements that we designate as 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.

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. These deferred costs are determined using judgments and assumptions that management considers reasonable.

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

G&A Expenses. We historically paid an affiliate for the direct and indirect G&A expenses our affiliate incurred on our behalf and another affiliate reimbursed us for the expenses in excess of a G&A cap. The provisions of the agreements under which we paid an affiliate and were reimbursed by another affiliate for G&A costs expired in 2008.

Equity-Based Incentive Compensation Awards. The compensation committee of our general partner has approved performance awards of phantom units representing limited partner interests in us to certain employees. In addition, our general partner has issued phantom units with distribution equivalent rights to our independent directors. These awards are accounted for as prescribed in ASC 718, *Compensation-Stock Compensation*.

Under ASC 718, we classify unit award grants as either equity or liabilities. Fair value for awards classified as equity is determined on the grant date of the award. We calculate the fair value for equity awards as the closing price of our limited partner units on the grant date reduced by the present value of projected per-unit distributions during the requisite service period. 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 the projected distributions to be paid over the remainder of the vesting period. We use the risk-free interest rate as the discount rate in calculating fair value of the equity and liability awards. Compensation expense for awards classified as equity is calculated as the fair value of those unit awards multiplied by the percentage of the requisite service period completed multiplied by the expected payout percentage less previously-recognized compensation expense. Compensation expense for awards classified as liabilities is calculated as the re-measured fair value of the performance awards multiplied by the percentage of the requisite service period completed multiplied by the expected payout percentage less previously-recognized compensation expense.

Certain unit awards include performance and other provisions that can result in payouts to the recipients of 0% up to 200% of the amount of the award. Additionally, certain unit award grants 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.

Contingencies and Environmental. Environmental expenditures that relate to current or future revenues 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, 2010, expected payments on our discounted environmental liabilities were $0.2 million in 2011, $0.1 million in 2012, less than $0.1 million in 2013, $0.1 million in 2014, $1.6 million in 2015 and $7.1 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 17–*Commitments and Contingencies* for a discussion of the changes in our environmental liabilities between December 31, 2009 and December 31, 2010.

	December 31, 2009	December 31, 2010
Aggregated undiscounted environmental liabilities	$40,102	$38,229
Amount of discount on environmental liabilities	(5,665)	(5,455)
Environmental liabilities, as reported	$34,437	$32,774

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 become insolvent or are otherwise unable to perform their obligations to us.

The determination of the accrual amounts recorded for environmental liabilities include 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"). Prior to the simplification, the non-controlling owners' interest on our balance sheet reflected the portion of Partners owned by its partners other than Holdings. At December 31, 2008, the non-controlling owners' interest was approximately 98%. At December 31, 2009, following the simplification 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 (see Note 1-*Organization and Description of Business-Newly Formed Entities*).

Income Taxes. We are a partnership for income tax purposes and therefore have not been subject to federal income taxes 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 the net revenues of our assets apportioned to the state of Texas.

Allocation of Net Income. For periods prior to the simplification, net income allocated to non-controlling owners' interest was determined by deducting MMP GP's allocated share of Partners' net income for the period from Partners' net income. MMP GP's allocated share of Partners' net income was determined by multiplying Partners' net income by MMP GP's proportionate share of distributions (including incentive distribution rights) for the period, adjusted for direct charges by Partners to MMP GP, plus MMP GP's approximate 2% ownership interest in undistributed Partners' net income, if any.

Through December 2008, the net income remaining after the net income allocation to the non-controlling owners' interest was allocated to Holdings GP and Holdings' limited partners based on their respective ownership interests, with adjustments made for any charges specifically allocated to Holdings GP. Holdings acquired Holdings GP in December 2008; therefore, all of its net income subsequent to that date was allocable to its limited partners. Following the simplification, we allocated all of our net income to our limited partners until the formation of MCO in May 2010. Following the formation of MCO, which is partially owned by a private investment group, we have allocated the non-controlling owners' interests their share of MCO's net losses.

Net Income Per Unit. We calculate basic net income per 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 unit for each period is the same calculation as basic net income per unit, except the weighted-average limited partner units outstanding include 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 have been retrospectively restated for the reverse unit split that occurred in association with the simplification.

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. We have recorded total comprehensive income with our consolidated statement of owners' equity as allowed under ASC 220.

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

	Derivative Gains (Losses)	Pension and Postretirement Liabilities	Accumulated Other Comprehensive Loss*
Balance, January 1, 2008	$ 3,817	$ (8,411)	$ (4,594)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	(164)
Amortization of net prior service credit and net actuarial loss	—	(88)	(88)
Adjustment to recognize the funded status of postretirement benefit plans	—	(12,272)	(12,272)
Balance, December 31, 2008	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)	—	(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 benefit plans	—	(4,783)	(4,783)
Balance, December 31, 2010	$ 3,325	$(14,421)	$(11,096)

* Includes amounts allocated to the non-controlling owners' interest.

New Accounting Pronouncements

On February 24, 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 Securities and Exchange Commission ("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 requires 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 are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. Our adoption of the applicable sections of this ASU did not have a material impact on our financial position, results of operations or cash flows. The adoption of the remaining provisions of this ASU will not have a material impact on our financial position, results of operations or cash flows.

In August 2009, the FASB issued ASU No. 2009-05, an update to ASC 820-10-35, *Fair Value Measurements and Disclosures*. This ASU provides guidance on measuring the fair value of liabilities. The guidance in this ASU was effective for the first reporting period, including interim periods, beginning after August 28, 2009. Our adoption of this ASU on September 1, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*. The new codification supersedes all existing GAAP standards and became the single source of GAAP authoritative literature, effective for financial statements issued for interim and annual periods ending after September 15, 2009.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events (as amended)*. This Statement requires the disclosure of subsequent events to be distinguished between recognized and non-recognized subsequent events. Further, entities are required to include a description of the period through which they evaluate subsequent events. (Note: ASU No. 2010-09 superseded the requirement to disclose the period through which entities who file statements with the SEC evaluate subsequent events). Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position ("FSP") No. FAS 107-1 and Accounting Principles Board ("APB") 28-1, *Interim Disclosures About Fair Value of Financial Instruments*. This FSP amended SFAS No. 107 (FASB ASC 825-10) and APB Opinion No. 28: (FASB ASC 270-10) by requiring quarterly as well as annual disclosures of the fair value of all financial instruments. The disclosures are to be in a form that makes it clear whether the fair value and carrying amounts represent assets or liabilities and how the carrying amounts relate to what is reported on the balance sheet. Our adoption of this FSP on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination that Arise from Contingencies*. This FSP amended and clarified FASB Statement No. 141 (revised 2007), *Business Combinations*, to address application issues on the initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP was effective for assets or liabilities arising from contingencies in business combinations that occurred following the start of the first fiscal year that begins on or after December 15, 2008. Our adoption of this FSP did not have a material impact on our financial position, results of operations or cash flows.

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2008	2009	2010
Restricted cash	$ —	$ —	$(14,379)
Trade accounts receivable and other accounts receivable	24,270	(31,872)	(17,173)
Inventory	72,728	(59,135)	(23,407)
Energy commodity derivatives contracts, net of derivatives deposits	(1,206)	(8,181)	3,694
Supply agreement deposit	(18,500)	—	—
Reimbursable costs	(4,964)	(5,104)	(590)
Accounts payable	(253)	(3,909)	7,794
Accrued payroll and benefits	(1,739)	8,416	2,093
Accrued interest payable	7,880	17,800	2,922
Accrued taxes other than income	(894)	1,110	5,378
Accrued product purchases	(19,356)	12,923	10,527
Current and noncurrent environmental liabilities	(18,368)	(7,383)	(2,038)
Other current and noncurrent assets and liabilities	(7,431)	3,562	8,998
Total	$ 32,167	$(71,773)	$(16,181)

At December 31, 2008, 2009 and 2010, the long-term pension and benefits liability was increased (decreased) by $12.3 million, $(9.8) million and $4.8 million respectively, resulting in a corresponding increase (decrease) in accumulated other comprehensive loss. These non-cash amounts were reflected in the consolidated financial statements but were not reflected in the statements of cash flows.

4. Allocation of Net Income

The allocation of net income in 2008 and 2009 for purposes of both calculating earnings per unit and determining the capital balances of the general partner, limited partners and the non-controlling owners' interest is provided in the following table (in thousands). Our organization structure changed in 2009, which resulted in all of our net income being allocated to the limited partners until May 2010, when we formed MCO, which was partially owned by a private investment group. Therefore, for the year ended December 31, 2010, all of our net income was allocated to our limited partners, except for the portion of MCO losses ($0.4 million) that was allocated to this private investment group.

	Year Ended December 31,	
	2008	2009
Net income	$330,103	$226,475
Net income applicable to non-controlling owners' interest[a]	244,430	99,729
Net income applicable to limited partners and Holdings GP	85,673	126,746
Allocation of net income applicable to limited partners and Holdings GP:		
Direct charges to Holdings GP:		
Reimbursable G&A costs	2,072	—
Income applicable to limited partners and Holdings GP before direct charges to Holdings GP	87,745	126,746
Holdings GP's share of income[b]	0.0130%	—
Holdings GP's allocated share of net income before direct charges	12	—
Direct charges to Holdings GP	2,072	—
Net loss allocated to Holdings GP	$ (2,060)	$ —
Net income applicable to limited partners and Holdings GP	$ 85,673	$126,746
Less: net loss allocated to Holdings GP[b]	(2,060)	—
Net income allocated to limited partners	$ 87,733	$126,746

(a) These amounts represent Partners' allocation of pre-simplification net income to the non-controlling owners' interest. We completed the simplification (see Note 2–*Summary of Significant Accounting Policies*) during the third quarter of 2009. In that transaction, we dissolved Holdings and eliminated Partners' incentive distribution rights; therefore, there were no longer non-controlling owners' interests and all of Partners' net income was allocated to the limited partners.

(b) In December 2008, Holdings acquired Holdings GP, and subsequently, Holdings GP was no longer allocated a portion of consolidated net income.

5. Acquisitions

Acquisition of Assets

In April 2010, we acquired various petroleum products storage tanks already connected to our petroleum pipeline system at Des Moines, Iowa, El Dorado, Kansas and Glenpool and Tulsa, Oklahoma for $29.3 million. We accounted for these purchases as the acquisition of assets. The operating results of these assets have been included in our petroleum pipeline system segment from the acquisition date.

Acquisitions of Businesses

We accounted for the following acquisitions as business combinations under the acquisition method of accounting in accordance with ASC 805, *Business Combinations*.

Houston-to-El Paso Pipeline

In July 2009, we acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. (which we refer to herein as the "Houston-to-El Paso pipeline acquisition") for $252.3 million plus the market value of the linefill of $86.1 million. The operating results from this acquisition have been included in the petroleum pipeline system segment's results since the acquisition date.

The Houston-to-El Paso pipeline acquisition primarily included an approximate 700-mile common carrier pipeline system that transports refined petroleum products from Houston to El Paso, Texas and a terminal in El Paso, Texas. The El Paso, Texas terminal serves local petroleum products demand and distributes product to connecting third-party pipelines for ultimate delivery to markets in Arizona, New Mexico and Northern Mexico. We have connected this pipeline system to our existing East Houston, Texas terminal to provide additional supply options for current and potential customers to transport petroleum products to southwestern markets.

We recorded the assets acquired and liabilities assumed at their estimated fair market values as of the acquisition date. The purchase price and assessment of the fair value of the assets acquired and liabilities assumed were as follows (in thousands):

Purchase price	$ 338,439
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$ 252,327
Inventory	86,132
Environmental liabilities	(20)
Total	$ 338,439

Oklahoma Terminal

In September 2009, we acquired a terminal in Oklahoma for $20.0 million in a sale/lease-back arrangement. The assets acquired were recorded at their estimated fair market values as of the acquisition date in our petroleum pipeline segment. The primary purpose of this acquisition was to provide additional storage capacity to our customers. The purchase price and assessment of the fair value of the assets acquired was as follows (in thousands):

Purchase price	$ 20,003
Fair value of assets acquired:	
Property, plant and equipment	$ 20,003

Louisiana Terminal

In October 2009, we acquired a facility for $32.2 million to expand one of our existing storage terminals in Louisiana. The increased storage capacity and the cost and operational synergies afforded from acquiring a facility adjacent to ours were the primary reasons for this acquisition. We recorded the assets acquired at their estimated fair market values as of the acquisition date in our petroleum terminals segment. The purchase price and assessment of the fair value of the assets acquired and liabilities assumed were as follows (in thousands):

Purchase price	$ 32,164
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$ 32,279
Other intangibles	2,041
Other current liabilities	(586)
Other noncurrent liabilities	(1,570)
Total	$ 32,164

Pipelines and Crude Oil Storage Facilities in Texas and Oklahoma

In September 2010, using proceeds from a combination of debt and equity offerings (see Note 12—*Debt* and Note 21—*Owners' Equity*), we acquired an aggregate 7.8 million barrels of crude oil storage in the Cushing, Oklahoma area and more than 100 miles of active petroleum pipelines in the Houston, Texas area from BP Pipelines (North America), Inc. ("BP") for $291.3 million. The purchase price exceeded the preliminarily-determined fair value amounts of the acquired net assets and, accordingly, $25.2 million was allocated to goodwill, of which $12.3 million was allocated to our petroleum pipeline system segment and $12.9 million was allocated to our petroleum terminals segment. Additionally, related to this transaction, during October 2010, we acquired certain crude oil tank bottoms at a fair value of approximately $53.0 million. These assets have improved our connectivity with existing markets as well as expanded our crude oil logistics infrastructure. We have leased a majority of the crude oil storage included in this acquisition to BP for an intermediate period.

We are still in the process of determining the fair value of the assets acquired and liabilities assumed and the final allocation of the purchase price will be made when that process is completed. The preliminary purchase price and initial assessment of the fair value of the assets acquired and liabilities assumed were as follows (in thousands):

Purchase price	$ 291,292
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$ 262,718
Other current assets	2,877
Goodwill	25,159
Other intangibles	3,898
Environmental liabilities	(375)
Other current liabilities	(2,985)
Total	$ 291,292

Revenues and net operating margin from the business acquired from BP included in our operating results for the current year were as follows (in thousands):

	Year Ended December 31, 2010		
	Petroleum Pipeline System Segment	Petroleum Terminals Segment	Total
Revenues	$13,399	$ 5,155	$ 18,554
Net operating margin*	$15,137	$ 3,985	$ 19,122

* See Note 16—*Segment Disclosures* for a definition of operating margin. The business we acquired from BP included crude oil and refined products pipelines. As allowed under our tariff agreements with our customers, we 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 in the shipping process, which we refer to as "tender deductions". We record the value of these tender deductions as a reduction of our operating expenses. During the period of transitioning the operations of these pipelines from BP to our control, the expenses for the first four months that we owned these pipelines in 2010 were minimal. As a result, the value of the tender deductions exceeded the operating expenses of those pipelines during that period.

Acquisition-related expenses of $0.6 million were included with our operating results through December 31, 2010.

Pro Forma Information

The following summarized pro forma consolidated income statement information assumes that the acquisitions of businesses referred to above occurred as of January 1, 2009. These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had these acquisitions been completed on January 1, 2009 or the results that will be attained in the future. The amounts presented below are in thousands:

	Year Ended December 31, 2009		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$1,014,171	$64,933	$1,079,104
Net income	$ 226,475	$ (7,711)	$ 218,764

	Year Ended December 31, 2010		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$1,557,447	$36,483	$1,593,930
Net income	$ 311,580	$15,740	$ 327,320

Significant pro forma adjustments include historical results of the acquired assets and our calculation of G&A, depreciation expense and interest expense on borrowings necessary to finance the acquisitions. Acquisition and start-up costs related to the BP assets totaling $0.6 million were reclassified from 2010 to 2009, as the acquisition was assumed to have been completed January 1, 2009 for this presentation.

The pro forma net income adjustments for 2009 include historical revenues and operating results from the Houston-to- El Paso pipeline section assets, which had minimal commercial activity following the former owner's bankruptcy filing in 2008.

6. Inventory

Inventory at December 31, 2009 and 2010 was as follows (in thousands):

	2009	2010
Refined petroleum products	$152,776	$146,211
Natural gas liquids	17,263	27,982
Transmix	17,230	32,277
Other	5,732	9,938
Total inventory	$193,001	$216,408

7. Product Sales Revenues

The amounts reported as product sales revenues on our consolidated statements of income include revenues from the physical sale of petroleum products and from mark-to-market adjustments from NYMEX contracts. We use NYMEX contracts as economic hedges against changes in the price of petroleum products we expect to sell from our business activities in which we acquire or produce petroleum products. Some of the NYMEX contracts we have entered into have qualified for hedge accounting treatment under ASC 815, *Derivatives and Hedging*, while others have not.

For the years ended December 31, 2008, 2009 and 2010, product sales revenues included the following (in thousands):

	Year Ended December 31,		
	2008	2009	2010
Physical sale of petroleum products	$523,158	$373,055	$784,839
NYMEX contract adjustments:			
Change in value of NYMEX contracts that did not qualify for hedge accountingtreatment and the effective portion of losses of matured NYMEX contracts that qualified for hedge accounting treatment associated with our petroleum products blending and fractionation activities(1)	50,937	(28,732)	(10,751)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with the Houston-to-El Paso pipeline section linefill working inventory(1)	—	(9,858)	(11,212)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment and the discontinuance of a cash flow hedge associated with our crude oil activities	—	—	214
Total NYMEX contract adjustments	50,937	(38,590)	(21,749)
Total product sales revenues	$574,095	$334,465	$763,090

(1) The associated petroleum products for these activities are classified as inventories in current assets on our consolidated balance sheets.

8. Property, Plant and Equipment

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

	December 31,		Estimated Depreciable Lives
	2009	2010	
Construction work-in-progress	$ 101,265	$ 106,699	
Land and rights-of-way	68,603	75,568	
Carrier property	1,743,606	1,922,131	6 – 59 years
Buildings	26,877	34,323	20 – 53 years
Storage tanks	620,719	829,306	20 – 40 years
Pipeline and station equipment	260,344	290,343	3 – 59 years
Processing equipment	496,087	546,426	3 – 56 years
Other	81,105	89,814	3 – 48 years
Total	$3,398,606	$3,894,610	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes interest capitalized at December 31, 2009 and 2010 of $24.5 million and $24.9 million, respectively. Depreciation expense for the years ended December 31, 2008, 2009 and 2010 was $85.0 million, $95.6 million and $107.3 million, respectively.

9. Major Customers and Concentration of Risks

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 2008, 2009 or 2010. The majority of the revenues from Customers A and B resulted from sales to those customers of refined petroleum products associated with the management of our linefill for the Houston-to-El Paso pipeline section and that were generated in connection with our petroleum products blending and fractionation activities, all of which are activities conducted by our petroleum pipeline system segment. In general, accounts receivable from these customers are due within 3 days of sale. If these customers were unable to purchase petroleum products from us, we believe that other companies would purchase the products from us.

	Year Ended December 31,		
	2008	2009	2010
Customer A	12%	5%	13%
Customer B	12%	11%	11%
Total	24%	16%	24%

Concentration of Risks. We transport, store and distribute petroleum products for refiners, marketers, traders and end-users of those products. We derive the major concentration of our petroleum pipeline system's revenues from activities conducted in the central United States. We generally secure transportation and storage revenues with warehouseman's liens. We periodically evaluate the financial condition and creditworthiness of our customers and require additional security, as we deem necessary.

As of December 31, 2010, we had 1,271 employees. At December 31, 2010, the labor force of 542 employees assigned to our petroleum pipeline system was concentrated in the central United States. Approximately 39% of these employees were represented by the United Steel Workers Union ("USW"). Our collective bargaining agreement with the USW expires January 31, 2012. The labor force of 284 employees assigned to our petroleum terminals operations at December 31, 2010 was primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 9% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2013. At December 31, 2010, the labor force of 20 employees assigned to our ammonia pipeline system was concentrated in the central United States. None of these employees was covered by a collective bargaining agreement.

10. Employee Benefit Plans

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

The annual measurement date of these plans is December 31. The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years ended December 31, 2009 and 2010 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2009	2010	2009	2010
Change in benefit obligation:				
Benefit obligation at beginning of year	$51,198	$ 60,657	$ 19,157	$ 13,352
Service cost	6,583	6,720	407	319
Interest cost	3,210	3,341	899	992
Plan participants' contributions	—	—	115	165
Actuarial (gain) loss	1,550	2,394	(6,738)	4,738
Benefits paid	(1,884)	(1,166)	(488)	(656)
Benefit obligation at end of year	60,657	71,946	13,352	18,910
Change in plan assets:				
Fair value of plan assets at beginning of year	38,213	51,006	—	—
Employer contributions	7,371	5,677	373	491
Plan participants' contributions	—	—	115	165
Actual return on plan assets	7,306	5,901	—	—
Benefits paid	(1,884)	(1,166)	(488)	(656)
Fair value of plan assets at end of year	51,006	61,418	—	—
Funded status at end of year	$ (9,651)	$(10,528)	$(13,352)	$(18,910)
Accumulated benefit obligation	$46,380	$ 54,514		

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2010	2009	2010
Amounts recognized in consolidated balance sheet:				
Current accrued benefit cost	$ —	$ —	$ (421)	$ (473)
Long-term pension and benefit cost	(9,651)	(10,528)	(12,931)	(18,437)
	(9,651)	(10,528)	(13,352)	(18,910)
Accumulated other comprehensive loss:				
Net actuarial loss (gain)	11,308	10,837	(699)	3,905
Prior service cost (credit)	1,261	954	(2,126)	(1,275)
	12,569	11,791	(2,825)	2,630
Net amount recognized in consolidated balance sheet	$ 2,918	$ 1,263	$(16,177)	$(16,280)

Net periodic benefit expense for the years ended December 31, 2008, 2009 and 2010 and other changes in plan assets and benefit obligations recognized in other comprehensive loss during 2009 and 2010 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2008	2009	2010	2008	2009	2010
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 5,473	$ 6,583	$ 6,720	$ 435	$ 407	$ 319
Interest cost	2,698	3,210	3,341	1,029	899	992
Expected return on plan assets	(2,702)	(2,723)	(3,552)	—	—	—
Amortization of prior service cost (credit)	307	307	307	(852)	(851)	(851)
Amortization of net actuarial loss	150	1,630	517	307	170	133
Net periodic expense	$ 5,926	$ 9,007	$ 7,333	$ 919	$ 625	$ 593

	Pension Benefits		Other Postretirement Benefits	
	2009	2010	2009	2010
Other changes in plan assets and benefit obligations recognized in other comprehensive loss:				
Net actuarial loss (gain)	$(3,033)	$ 45	$(6,738)	$4,738
Amortization of net actuarial loss	(1,630)	(517)	(170)	(133)
Amortization of prior service credit (cost)	(307)	(307)	851	851
Total recognized in other comprehensive loss	(4,970)	(779)	(6,057)	5,456
Net periodic expense	9,007	7,333	625	593
Total recognized in net periodic benefit cost and other comprehensive loss	$ 4,037	$6,554	$(5,432)	$6,049

Expenses related to the defined contribution plan were $5.0 million, $5.3 million and $5.9 million in 2008, 2009 and 2010, respectively.

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2011 are $0.6 million and $0.3 million, respectively. The estimated net actuarial loss and prior service credit for the other defined benefit postretirement plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2011 are $0.3 million and $(0.9) million, respectively.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2009 and 2010 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2009	2010	2009	2010
Discount rate—Salaried plan	5.79%	5.54%	N/A	N/A
Discount rate—USW plan	5.72%	5.07%	N/A	N/A
Discount rate—IUOE plan	5.67%	5.52%	N/A	N/A
Discount rate—Other Postretirement Benefits	N/A	N/A	5.97%	5.56%
Rate of compensation increase—Salaried plan	5.00%	5.00%	N/A	N/A
Rate of compensation increase—USW plan	4.50%	4.50%	N/A	N/A
Rate of compensation increase—IUOE plan	5.00%	5.00%	N/A	N/A

The weighted-average rate assumptions used to determine net pension and other postretirement benefit expense for the years ended December 31, 2008, 2009 and 2010 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2008	2009	2010	2008	2009	2010
Discount rate—Salaried plan	6.50%	6.00%	5.79%	N/A	N/A	N/A
Discount rate—USW plan	6.50%	6.25%	5.72%	N/A	N/A	N/A
Discount rate—IUOE plan	6.50%	5.75%	5.67%	N/A	N/A	N/A
Discount rate—Other Postretirement Benefits	N/A	N/A	N/A	6.50%	5.75%	5.97%
Rate of compensation increase—Salaried plan	5.00%	5.00%	5.00%	N/A	N/A	N/A
Rate of compensation increase—USW plan	4.50%	4.50%	4.50%	N/A	N/A	N/A
Rate of compensation increase—IUOE plan	5.00%	5.00%	5.00%	N/A	N/A	N/A
Expected rate of return on plan assets—Salaried plan	7.00%	6.80%	6.80%	N/A	N/A	N/A
Expected rate of return on plan assets—USW plan	7.00%	6.80%	6.80%	N/A	N/A	N/A
Expected rate of return on plan assets—IUOE plan	7.00%	3.25%	3.25%	N/A	N/A	N/A

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

The annual assumed rate of increase in the health care cost trend rate for 2011 is 7.1% decreasing systematically to 4.2% by 2085 for pre-65 and post-65 year-old participants. The health care cost trend rate assumption has a significant effect on the amounts reported. As of December 31, 2010, a 1.0% change in assumed health care cost trend rates would have the following effect (in thousands):

	1% Increase	1% Decrease
Change in total of service and interest cost components	$ 241	$ 193
Change in postretirement benefit obligation	$3,329	$2,660

The fair value of the pension plan assets at December 31, 2009 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash	$ 23	$ 23	$ —	$ —
Domestic Equity Securities[a]:				
Small-cap fund	2,070	2,070	—	—
Mid-cap fund	4,702	4,702	—	—
Large-cap fund	6,193	6,193	—	—
International equity fund	7,630	7,630	—	—
Fixed Income Securities[a]:				
Intermediate-term bond funds	22,029	22,029	—	—
Long-term investment grade bond fund	6,426	6,426	—	—
Other:			—	—
Short-term investment fund	1,462	1,462	—	—
Group annuity contract	471	—	—	471
Fair value of plan assets	$51,006	$50,535	$ —	$ 471

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

The fair value of the pension plan assets at December 31, 2010 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities[a]:				
Small-cap fund	$ 2,403	$ 2,403	$ —	$ —
Mid-cap fund	5,405	5,405	—	—
Large-cap fund	7,182	7,182	—	—
International equity fund	8,998	8,998	—	—
Fixed Income Securities[a]:				
Intermediate-term bond funds	26,237	26,237	—	—
Long-term investment grade bond fund	7,898	7,898	—	—
Other:			—	—
Short-term investment fund	2,863	2,863	—	—
Group annuity contract	432	—	—	432
Fair value of plan assets	$61,418	$60,986	$ —	$ 432

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

The group annuity contract is held by MetLife and is valued at contract value, which approximates fair value as determined by MetLife. The balance at the end of the year represents total contributions plus interest earned less benefit payments and expenses paid. It is guaranteed a specified return based on the Barclays Capital Aggregate Bond Fund return. The fair value measurements for the MetLife group annuity contract which used significant unobservable inputs (Level 3) for the years ended December 31, 2009 and 2010 were as follows (in thousands):

	2009	2010
Beginning balance	$442	$471
Actual return on plan assets:		
Relating to assets still held at the reporting date	25	30
Purchases, sales and settlements	4	(69)
Ending balance	$471	$432

The investment strategy for the pension plan assets by asset category are as follows:

Asset Category	Fund's Investment Strategy
Domestic Equity Securities:	
Small-cap fund	Seeks to track performance of the Morgan Stanley Country Index ("MSCI") US Small Cap 1750 Index
Mid-cap fund	Seeks to track performance of the MSCI US Mid Cap 450 Index
Large-cap fund	Seeks to track performance of the Standard & Poor's 500 Index
International equity fund	Seeks long-term growth of capital by investing 80% of assets in international equities
Fixed Income Securities:	
Intermediate-term bond funds	Seeks to track performance of bond indexes representing fixed income securities having maturities greater than one year
Long-term investment grade bond fund	Seeks high and sustainable current income through investment in long- term high grade bonds
Other:	
Short-term investment fund	Invests primarily in high quality commercial paper and government securities
Group annuity contract	Guarantees a specified return based on a specified index

The expected long-term rate of return on plan assets was determined by combining a review of projected returns, historical returns of portfolios with assets similar to the current portfolios of the union and non-union pension plans and target weightings of each asset classification. Our investment objective for the assets within the pension plans is to earn a return that exceeds the growth of its obligations that result from interest and changes in the discount rate, while avoiding excessive risk. Defined diversification goals are set in order to reduce the risk of wide swings in the market value from year to year, or of incurring large losses that may result from concentrated positions. As a result, our plan assets have no significant concentrations of credit risk. Additionally, liquidity risks are minimized because all of the funds that the plans have invested in are publicly traded. We evaluate risks based on the potential impact of the predictability of contribution requirements, probability of under-funding, expected risk-adjusted returns and investment return volatility. Funds are invested with multiple investment managers. The target allocation and actual weighted-average asset allocation percentages at December 31, 2009 and 2010 were as follows:

	2009		2010	
	Actual[(a)]	Target	Actual[(a)]	Target
Equity securities	40%	40%	39%	40%
Debt securities	57%	59%	56%	59%
Other	3%	1%	5%	1%

(a) Cash contributions of $7.4 million and $5.7 million were made to the pension plans during 2009 and 2010, respectively. Amounts contributed in 2009 and 2010 in excess of benefit payments made were to be invested in debt and equity securities over a twelve-month period, with the amounts that remained uninvested as of December 31, 2009 and 2010 scheduled for investment in accordance with the target. Excluding these uninvested cash amounts, the actual allocation percentages at December 31, 2009 would have been 41% equity securities and 58% debt securities and at December 31, 2010, would have been 41% equity securities and 59% debt securities. In 2011, we will invest these uninvested cash amounts to bring the total asset allocation in line with the target allocation.

As of December 31, 2010, the benefit amounts we expect to pay through December 31, 2020 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2011	$ 2,488	$ 473
2012	2,895	554
2013	2,979	621
2014	3,369	630
2015	3,121	707
2016 through 2020	20,817	4,516

Contributions estimated to be paid into the plans in 2011 are $8.1 million and $0.5 million for the pension and other postretirement benefit plans, respectively.

11. 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 $0.7 million in 2008 and $0.8 million in both 2009 and 2010. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

Prior to the simplification of our capital structure in 2009 (see Note 2—*Summary of Significant Accounting Policies)*, we paid an affiliate for the direct and indirect G&A expenses our affiliate incurred on our behalf and another affiliate reimbursed us for the expenses in excess of a G&A cap. The amount of G&A costs required to be reimbursed was $1.6 million in 2008. The provisions of the agreements under which we paid an affiliate and were reimbursed by another affiliate for G&A costs expired in 2008.

During 2008, Partners and Holdings were allocated $0.4 million of non-cash G&A compensation expense, with a corresponding increase in owners' equity, for payments made by MGG Midstream Holdings, L.P., an affiliate, to one of our executive officers.

The following table summarizes affiliate costs and expenses that are included in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,	
	2008	2009
MGG Midstream Holdings GP, LLC—allocated operating expenses	$84,460	$69,523
MGG Midstream Holdings GP, LLC—allocated G&A expenses	44,482	41,890
MGG Midstream Holdings, L.P.—allocated G&A expenses	440	—

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 Holdings owned our general partner prior to the simplification, Holdings benefited from these distributions. In 2008 and the portion of 2009 prior to the simplification, distributions paid to Holdings by us totaled $85.6 million and $70.4 million, respectively. Until December 2008, certain of our executive officers owned a direct interest of approximately 4% in MGG Midstream Holdings, L.P, which in turn owned limited and general partnership interests in Holdings. Through that ownership interest, those executive officers benefited from our distributions prior to the simplification in September 2009. Following the simplification, Holdings' interests in us, including the interests indirectly held by our executive officers, were converted to limited partner interests and a non-economic general partner interest. As of December 31, 2010, our executive officers owned less than 1% of our limited partner units outstanding.

12. Debt

Debt at December 31, 2009 and 2010 was as follows (in thousands):

	December 31, 2009	December 31, 2010	Weighted-Average Interest Rate at December 31, 2010 (a)
Revolving credit facility	$ 101,600	$ 15,000	0.7%
6.45% Notes due 2014	249,732	249,786	6.3%
5.65% Notes due 2016	252,897	252,466	5.7%
6.40% Notes due 2018	260,340	259,125	5.9%
6.55% Notes due 2019	566,500	581,890	5.4%
4.25% Notes due 2021	—	298,932	4.3%
6.40% Notes due 2037	248,935	248,949	6.3%
Total debt	$1,680,004	$1,906,148	

(a) Weighted-average interest rate includes the impact of interest rate swaps and the amortization/accretion of discounts and premiums and gains and losses realized on various cash flow and fair value hedges (see Note 13-*Derivative Financial Instruments* for detailed information regarding the reclassification of the gains or losses from these hedges as adjustments to interest expense).

The face value of our debt outstanding as of December 31, 2010 was $1,865.0 million. 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. We amortize or accrete note discounts and premiums to the applicable notes over the respective lives of the associated notes. At December 31, 2010, maturities of our debt were as follows: $0 in 2011; $15.0 million in 2012; $0 in 2013; $250.0 million in 2014; $0 in 2015; and $1.6 billion thereafter.

2010 Debt Offering

In August 2010, we issued $300.0 million of 4.25% notes due 2021 in an underwritten public offering. We issued these notes for the discounted price of 99.6%, or $298.9 million. Net proceeds from this offering, after underwriting discounts of $2.0 million and offering costs of $0.4 million, were $296.5 million. The combined proceeds from this debt offering and our equity offering in July 2010 (see Note 21–*Owners' Equity*) were used to pay for the business and certain crude oil tank bottoms we acquired from BP (see Note 5–*Acquisitions*) and to repay the outstanding balance of the revolving credit facility at that time. We used the remaining amount of the net proceeds for general partnership purposes.

Other Debt

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in September 2012, was $550.0 million as of December 31, 2010. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, we are assessed a commitment fee at a rate from 0.05% to 0.125%, depending on our credit ratings. We use borrowings under this facility for general purposes, including capital expenditures. As of December 31, 2010, there was $15.0 million outstanding under this facility and $4.6 million was obligated for letters of credit. We do not recognize amounts obligated for letters of credit as debt on our consolidated balance sheets.

6.45% Notes due 2014. In May 2004, we sold $250.0 million aggregate principal of 6.45% notes due 2014 in an underwritten public offering. We issued these notes for the discounted price of 99.8%, or $249.5 million.

5.65% Notes due 2016. In October 2004, we issued $250.0 million of 5.65% notes due 2016 in an underwritten public offering. We issued these notes for the discounted price of 99.9%, or $249.7 million. The outstanding principal amount of the notes was increased $3.1 million and $2.6 million at December 31, 2009 and 2010, respectively, for the unamortized portion of a gain realized upon termination of a related interest rate swap.

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. The outstanding principal amount of the notes was increased $10.4 million and $9.1 million at December 31, 2009 and 2010, respectively, for the unamortized portion of gains realized upon termination or discontinuation of hedge accounting treatment of associated interest rate swaps.

6.55% Notes due 2019. In June and August 2009, we issued $550.0 million of 6.55% notes due 2019 in underwritten public offerings. We issued these notes at a net premium of 103.4%, or $568.7 million. In connection with these offerings, we entered into interest rate swap agreements to effectively convert $250.0 million of these notes to floating-rate debt. In May and June 2010, we terminated these interest rate swap agreements. We decreased the outstanding principal amount of the notes by $1.6 million at December 31, 2009 for the fair value less accrued interest of the associated interest rate swap agreements. The outstanding principal amount was increased $15.2 million at December 31, 2010 for the unamortized portion of the gain realized upon termination of the related interest rate swaps.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.40% notes due 2037 in an underwritten public offering. We issued these notes for the discounted price of 99.6%, or $248.9 million.

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 4.75 to 1.00. 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, 2010.

The revolving credit facility and notes described above are senior indebtedness.

During the years ending December 31, 2008, 2009 and 2010, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $49.3 million, $64.3 million and $101.3 million, respectively.

13. Derivative Financial Instruments

Commodity Derivatives

Our petroleum products blending activities produce gasoline products and we can estimate the timing and quantities of sales of these products. We use a combination of forward sales contracts and NYMEX contracts to lock in most of the product margins realized from our blending activities that we choose to hedge.

We account for the forward sales contracts we use in our blending activities as normal sales. As of December 31, 2010, 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 $27.7 million, and we had commitments under forward sales contracts for product sales of approximately 0.2 million barrels that are being accounted for as normal sales totaling approximately $25.2 million.

We use NYMEX contracts as economic hedges against changes in the price of petroleum products we expect to sell in future periods. Some of the NYMEX contracts we have entered into have qualified for hedge accounting treatment under ASC 815, *Derivatives and Hedging*, while others have not. At December 31, 2010, we had open NYMEX contracts, representing 2.9 million barrels of petroleum products, used as economic hedges for petroleum products we expect to sell in the future in connection with the following business activities:

- Petroleum products blending and fractionation—we had open NYMEX contracts maturing between January 2011 and July 2011 associated with these activities representing 1.0 million barrels of petroleum products that did not qualify as hedges for accounting purposes;
- Linefill on our Houston-to-El Paso pipeline section—we had open NYMEX contracts maturing between January 2011 and July 2011 associated with these activities representing 1.2 million barrels of petroleum products that did not qualify as hedges for accounting purposes; and
- Crude oil storage and pipeline:
  - At December 31, 2010, we had open NYMEX contracts associated with our crude oil tank bottom inventory for our Cushing storage facility. These contracts, representing 0.7 million barrels of crude oil, were designated as fair value hedges for accounting purposes and mature in November 2013.
  - At December 31, 2010, we had open NYMEX contracts associated with our crude oil pipeline linefill we acquired from BP in September 2010. These contracts, which mature in March 2011 and represent less than 0.1 million barrels of crude oil, did not qualify as hedges for accounting purposes.

At December 31, 2010, the fair value of our open NYMEX contracts was a net liability of $16.7 million, of which $11.8 million was recorded as energy commodity derivatives contracts and $4.9 million was recorded as other noncurrent liabilities on our consolidated balance sheet. At December 31, 2010, we had made margin deposits of $22.3 million for these contracts, which were recorded as energy commodity derivatives deposits on our consolidated balance sheet. We have the right to offset the fair value of our open NYMEX contracts against our margin deposits under a master netting arrangement with our counterpart; however, we have elected to separately disclose these amounts on our consolidated balance sheet. We have netted the fair value of our NYMEX agreements together in our consolidated balance sheets.

Interest Rate Derivatives

Interest Rate Derivatives Settled During 2010

In June and August 2009, we entered into $150.0 million and $100.0 million, respectively, of interest rate swap agreements to hedge against changes in the fair value of a portion of the $550.0 million of 6.55% notes due 2019, and we accounted for these agreements as fair value hedges. These agreements effectively converted $250.0 million of our 6.55% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we received the 6.55% fixed rate of the notes and paid six-month LIBOR in arrears plus 2.18% on $150.0 million of the swaps and 2.34% on the other $100.0 million. In May 2010, we terminated and settled $150.0 million of the swaps and received $9.6 million (excluding $1.8 million of accrued interest), which was recorded as an adjustment to long-term debt that is being amortized over the remaining life of the 6.55% notes. In June 2010, we terminated and settled the remaining $100.0 million of swaps and received $6.6 million (excluding $1.5 million of accrued interest), which was recorded as an adjustment to long-term debt that is being amortized over the remaining life of the 6.55% notes. We had no interest rate swaps outstanding as of December 31, 2010.

Interest Rate Derivatives Settled During 2009

In July 2008, we entered into a $50.0 million interest rate swap agreement (“Derivative A”) to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. Derivative A effectively converted $50.0 million of those notes from a 6.40% fixed rate to a floating rate of six-month LIBOR plus 1.83%. We originally accounted for Derivative A as a fair value hedge. In December 2008, in order to capture the economic value of Derivative A at that time, we entered into an offsetting derivative, as described below, and discontinued hedge accounting for Derivative A. We recorded the $5.4 million fair value of Derivative A at that time as an increase to long-term debt, which we are amortizing over the remaining life of the 6.40% fixed-rate notes due 2018. In December 2009, we terminated this swap and received cash proceeds of $3.4 million.

In December 2008, concurrent with the discontinuance of hedge accounting for Derivative A, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which it paid a fixed rate of 6.40% and received a floating rate of six-month LIBOR plus 3.23%. We entered into this agreement to offset changes in the fair value of Derivative A, excluding adjustments due to changes in counterparty credit risks. We did not designate this agreement as a hedge for accounting purposes. In December 2009, we terminated this swap and we received cash proceeds of $2.0 million.

Interest Rate Derivatives Settled During 2008

In July 2008, we entered into a $50.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. We accounted for this agreement as a fair value hedge. This agreement effectively converted $50.0 million of our 6.40% fixed-rate notes to floating-rate debt. In December 2008, we terminated and settled this interest rate swap agreement and received $6.3 million. We recorded this amount as an adjustment to long-term debt, which we are amortizing over the remaining life of the 6.40% fixed-rate notes.

In October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016. We accounted for this agreement as a fair value hedge. This agreement effectively converted $100.0 million of our 5.65% fixed-rate senior notes to floating-rate debt. In May 2008, we terminated and settled this interest rate swap agreement and received $3.8 million. We recorded this amount as an adjustment to long-term debt, which we are amortizing over the remaining life of the notes.

In January 2008, we entered into a total of $200.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipated issuing no later than June 2008. We expected to use the proceeds from the anticipated debt issuance to refinance borrowings on our revolving credit facility. In April 2008, we terminated and settled these interest rate swap agreements and received $0.2 million, which we recorded to other income on our consolidated statement of income.

The changes in derivative gains (losses) included in accumulated other comprehensive loss ("AOCL") for the years ended December 31, 2008, 2009 and 2010 were as follows (in thousands):

	Year Ended December 31,		
Derivative Gains (Losses) Included in AOCL	**2008**	**2009**	**2010**
Beginning balance	$3,817	$ 3,653	$ 1,743
Net loss on NYMEX commodity contracts	—	(6,804)	(4,283)
Reclassification of net gain on cash flow hedges to interest expense	(164)	(164)	(164)
Reclassification of net loss on commodity hedges to product sales revenues	—	5,058	5,438
Reclassification of loss on discontinuance of cash flow hedge to product sales revenues	—	—	591
Ending balance	$3,653	$ 1,743	$ 3,325

As of December 31, 2010, the net gain estimated to be classified to interest expense over the next twelve months from AOCL was approximately $0.2 million.

The following table provides a summary of the current impact of our historical derivative activity on long-term debt resulting from the termination of or the discontinuance of hedge accounting treatment of fair value hedges as of and for the years ended December 31, 2009 and 2010 (in thousands):

Hedge	Total Gain Realized	Unamortized Amount Recorded in Long-Term Debt		Amount Reclassified to Interest Expense from Long-Term Debt	
		As of December 31,		Year Ended December 31,	
		2009	2010	2009	2010
Fair value hedges (date executed):					
Interest rate swaps 6.40% Notes (July 2008)	$11,652	$10,358	$ 9,142	$(1,216)	$(1,216)
Interest rate swaps 5.65% Notes (October 2004)	3,830	3,093	2,638	(455)	(455)
Interest rate swaps 6.55% Notes (June and August 2009)	16,238	—	15,222	—	(1,016)
Total fair value hedges		$13,451	$27,002	$(1,671)	$(2,687)

The following table provides a summary of the effect on our consolidated statement of income for the years ended December 31, 2009 and 2010 of derivatives accounted for under ASC 815-25, *Derivatives and Hedging—Fair Value Hedges*, that were designated as hedging instruments (in thousands):

Derivative Instrument	Location of Gain Recognized on Derivative	Amount of Gain Recognized on Derivative		Amount of Interest Expense Recognized on Fixed-Rated Debt (Related Hedged Item)	
		Year Ended December 31,		Year Ended December 31,	
		2009	2010	2009	2010
Interest rate swap agreements	Interest expense	$4,446	$4,604	$(15,917)	$(17,277)

During 2010, we had open NYMEX contracts on 0.7 million barrels of crude oil which were designated as fair value hedges. The unrealized losses of $4.9 million from the agreements during 2010 were fully offset by an adjustment to tank bottom inventory; therefore, there was no net impact on product sales revenues in the current period.

The following tables provide a summary of the effect on our consolidated statement of income for the years ended December 31, 2009 and 2010 of the effective portion of derivatives accounted for under ASC 815-30, *Derivatives and Hedging—Cash Flow Hedges*, that were designated as hedging instruments (in thousands):

	Year Ended December 31, 2009		
Derivative Instrument	Amount of Gain (Loss) Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate swap agreements	$ —	Interest expense	$ 164
NYMEX commodity contracts	(6,804)	Product sales revenues	(5,058)
Total cash flow hedges	$(6,804)	Total	$(4,894)

	Year Ended December 31, 2010		
Derivative Instrument	Amount of Gain (Loss) Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate swap agreements	$ —	Interest expense	$ 164
NYMEX commodity contracts	(4,283)	Product sales revenues	5,438
Total cash flow hedges	$(4,283)	Total	$ 5,602

During the year ended December 31, 2010, we recorded $0.6 million of losses previously deferred in AOCL to product sales revenues due to discontinuing our cash flow hedge as the forecasted transaction was no longer probable of occurring within two months of the originally specified transaction date. There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the years ended December 31, 2009 and 2010.

The following table provides a summary of the effect on our consolidated statement of income for the years ended December 31, 2009 and 2010 of derivatives accounted for under ASC 815-10-35; Paragraph 2, *Derivatives and Hedging—Overall—Subsequent Measurement*, that were not designated as hedging instruments (in thousands):

Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	Amount of Gain (Loss) Recognized on Derivative — Year Ended December 31, 2009	2010
Interest rate swap agreements	Other income	$ 279	$ —
NYMEX commodity contracts	Product sales revenues	(33,532)	(15,720)
	Total	$(33,253)	$(15,720)

The following tables provide a summary of the amounts included in our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging,* that were designated as hedging instruments as of December 31, 2009 and 2010 (in thousands):

	December 31, 2009			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Interest rate swap agreements, current portion	Other current assets	$4,446	Other current liabilities	$ —
Interest rate swap agreements, noncurrent portion	Other noncurrent assets	—	Other noncurrent liabilities	1,649
NYMEX commodity contracts	Energy commodity derivatives contracts	—	Energy commodity derivatives contracts	1,211
	Total	$4,446	Total	$2,860

	December 31, 2010			
	Asset Derivatives		Liability Derivatives	
NYMEX commodity contracts	Other noncurrent assets	$ —	Other noncurrent liabilities	$4,920

The following tables provide a summary of the amounts included in our consolidated balance sheet of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging,* that were not designated as hedging instruments as of December 31, 2009 and 2010 (in thousands):

	December 31, 2009			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
NYMEX commodity contracts	Energy commodity derivatives contracts	$ —	Energy commodity derivatives contracts	$ 8,046
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	1,146
	Total	$ —	Total	$ 9,192

	December 31, 2010			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
NYMEX commodity contracts	Energy commodity derivatives contracts	$ —	Energy commodity derivatives contracts	$11,790

14. Leases

Leases—Lessee. We lease land, office buildings and terminal equipment at various locations to conduct our respective business operations. Several of the agreements provide for negotiated renewal options and cancellation penalties, some of which include the requirement to remove our pipeline from the property for non-performance. Management expects that we will generally renew our expiring leases. Leases are evaluated at inception or at any subsequent material modification and, depending on the lease terms, are classified as either capital or operating leases, as appropriate under ASC 840, *Leases*. We recognize rent expense on a straight-line basis over the life of the lease. Total rent expense was $4.6 million, $5.2 million and $4.0 million for the years ended December 31, 2008, 2009 and 2010, respectively. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2010, were as follows (in thousands):

2011	$ 2,415
2012	2,373
2013	1,290
2014	929
2015	854
Thereafter	12,947
Total	$20,808

Leases—Lessor. We have entered into capacity and storage leases with our customers with remaining terms from one to 20 years that are accounted for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum payments receivable under these arrangements as of December 31, 2010, were as follows (in thousands):

2011	$157,848
2012	148,504
2013	129,243
2014	114,754
2015	93,500
Thereafter	305,752
Total	$949,601

15. Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan ("LTIP") covering certain of our employees and directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 3.2 million of our limited partner units. The remaining units available under the LTIP at December 31, 2010 total 0.3 million. The compensation committee of our general partner's board of directors ("compensation committee") administers the LTIP and they have approved the unit awards described below.

Vested Unit Awards

Grant Date	Unit Awards Granted	Forfeitures / Settlements	Adjustments to Unit Awards for Attaining Above-Target Financial Results	Vested Limited Partner Units	Vesting Date	Value of Unit Awards on Vesting Date (Millions)
February 2005	160,640	11,348	149,292	298,584	12/31/2007	$12.9
June 2006	1,170	—	1,170	2,340	12/31/2007	$ 0.1
February 2006	168,105	13,730	154,143	308,518	12/31/2008	$ 9.3
Various 2006	9,201	2,640	6,561	13,122	12/31/2008	$ 0.4
March 2007	2,640	—	—	2,640	12/31/2008	$ 0.1
January 2007	159,691	3,776	62,190	218,105	12/31/2009	$ 9.5
January 2008	189,832	4,987	184,803	369,648	12/31/2010	$20.9
Various 2008 & March 2009	14,248	—	—	14,248	12/31/2010	$ 0.8

We settled the above-noted awards as indicated in the table below and the impact on our cash flows was as follows:

Grant Date	Vested Limited Partner Units	Minimum Tax Withholdings	Limited Partner Units Issued to Participants	Tax Withholdings and Employer Taxes Paid (Millions)	Settlement Date
February 2005	298,584				
June 2006	2,340				
	300,924	104,068	196,856	$ 5.1	January 2008
February 2006	308,518				
Various 2006	13,122				
March 2007	2,640				
	324,280	114,960	209,320	$ 4.0	January 2009
January 2007	218,105	77,788	140,317	$ 3.9	January 2010
January 2008	369,648				
Various 2008 & March 2009	14,248				
	383,896	131,150	252,746	*$8.3	January 2011

* There was no impact on our consolidated cash flows for the periods presented in this report associated with this cash payment. See Note 23—*Subsequent Events* for further discussion of this matter.

Performance Based Unit Awards

Performance awards granted under our LTIP are subject to forfeiture by an award recipient if their employment is terminated for any reason other than retirement, death or disability prior to the vesting date. If an award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's award is prorated based upon the completed months of employment during the vesting period and the award is settled at the end of the vesting period. Our agreement with the award recipients requires the LTIP awards described below to be paid out in our limited partner units. The award grants do not have an early vesting feature except under certain circumstances following a change in control of our general partner.

On September 30, 2009, our general partner became our wholly owned subsidiary, which resulted in a change in control as defined in the LTIP. Even though a change in control has occurred, participants in the LTIP must resign voluntarily for good reason or be terminated involuntarily for other than performance reasons within two years of September 30, 2009 in order to receive enhanced LTIP payouts. As of December 31, 2010, only one enhanced LTIP payout has occurred associated with the September 2009 change of control.

For each of the award grants listed below, we base the payout calculation for 80% of the unit awards solely on the attainment of a financial metric established by the compensation committee. We account for this portion of the award grants as equity. We base the payout calculation for the remaining 20% of the unit awards on both the attainment of a financial metric and the individual employee's personal performance as determined by the compensation committee. We account for this portion of the award grants as a liability.

The table below summarizes the performance based unit awards granted by the compensation committee that had not vested as of December 31, 2010. There was no impact to our consolidated cash flows associated with these award grants for the periods presented in this report.

Grant Date	Unit Awards Granted	Estimated Forfeitures	Adjustment to Unit Awards in Anticipation of Achieving Above Target Financial Results	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense (Millions)(1)	Intrinsic Value of Unvested Awards at December 31, 2010 (Millions)
2009 Awards	275,994	8,280	133,857	401,571	12/31/2011	$3.5	$22.7
2010 Awards	203,212	6,097	—	197,115	12/31/2012	5.0	11.1
Total	479,206	14,377	133,857	598,686		$8.5	$33.8

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the awards.

At its February 2009 meeting, the compensation committee adjusted the threshold, target and stretch performance levels for the 2008 awards to reflect the downturn in the economic environment. The compensation committee felt that the modifications were necessary to ensure that the motivational and retention features of the awards remained potent in the economic environment at that time and maintain the link necessary to encourage our key employees to maximize our long-term financial results. The 2008 awards vested on December 31, 2010 (see *Vested Unit Awards* above).

Retention Awards

The table below summarizes the retention awards granted by the compensation committee that had not vested as of December 31, 2010. These award grants generally do not have an early vesting feature and are subject to forfeiture if employment is terminated or the employee resigns from their current position for any reason prior to the applicable vesting date. We account for these award grants as equity. There was no impact to our consolidated cash flows associated with these award grants for the periods presented in this report:

Grant Date	Unit Awards Granted	Estimated Forfeitures	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense (Millions)(1)	Intrinsic Value of Unvested Awards at December 31, 2010 (Millions)
Various 2008	40,315	5,242	35,073	12/31/2011	$0.2	$2.0
March 2009	2,240	291	1,949	12/31/2011	*	0.1
Various 2010	42,979	1,935	41,044	12/31/2012	1.0	2.3
	85,534	7,468	78,066		$1.2	$4.4

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the awards.
* Amounts are less than $0.1 million.

Fair Value of Unit Awards

	December 31, 2010			
	2008 Awards	2009 Awards	2010 Awards	Retention Awards
Weighted-average per unit grant date fair value of equity awards[(a)]	$28.58	$19.61	$35.04	$29.05
December 31, 2010 per unit fair value of liability awards[(b)]	$56.50	$53.37	$50.85	N/A

(a) We account for approximately 80% of the unit awards as equity (see *Performance Based Unit Awards* above). For the 2008 and 2009 awards, we calculated fair value as our unit price on the grant date less the present value of estimated cash distributions during the vesting period. For the 2010 awards, we calculated fair value as our unit price on the grant date less the present value of annual cash distributions of $2.84 per unit during the vesting period (the LTIP recipients will receive the value of distributions paid in excess of $2.84 when these awards vest).

(b) We account for approximately 20% of the unit awards as liabilities (see *Performance Based Unit Awards* above). For the 2008 and 2009 awards, we calculated fair value as our unit price at the end of each accounting period less the present value of estimated cash distributions during the remaining portion of the vesting period. For the 2010 awards, we calculated fair value as our unit price at the end of each accounting period less the present value of annual cash distributions of $2.84 per unit during the remaining portion of the vesting period.

Compensation Expense Summary

Equity-based incentive compensation expense, excluding amounts for directors, for 2008, 2009 and 2010 was as follows (in thousands):

	Year Ended December 31, 2008		
	Equity Method	Liability Method	Total
2005 awards	$ —	$ 26	$ 26
2006 awards	2,509	378	2,887
2007 awards	990	127	1,117
2008 awards	457	82	539
Retention awards	182	—	182
Total	$4,138	$613	$4,751

	Year Ended December 31, 2009		
	Equity Method	Liability Method	Total
2007 awards	$ 3,842	$1,526	$ 5,368
2008 awards	1,243	534	1,777
2009 awards	1,400	668	2,068
Retention awards	409	—	409
Total	$ 6,894	$2,728	$ 9,622

	Year Ended December 31, 2010		
	Equity Method	Liability Method	Total
2007 awards	$ —	$ 6	$ 6
2008 awards	6,763	3,802	10,565
2009 awards	2,800	2,189	4,989
2010 awards	1,842	669	2,511
Retention awards	828	—	828
Total	$12,233	$6,666	$18,899

Director Equity-Based Compensation Expense

Pursuant to the LTIP, long-term incentive awards are granted to independent members of the board of directors of our general partner. Most directors elect to defer all or a portion of their compensation. The table below summarizes the phantom limited partner units earned by our independent directors who chose to defer their equity compensation and the related compensation expense recognized. The unit and compensation amounts below include amounts credited to the director's account for distribution equivalents earned (in thousands).

	Year Ended December 31,		
	2008	2009	2010
Phantom units earned by independent directors	13,950	14,123	15,001
Deferred director compensation expense	$ 507	$ 435	$ 676
Distribution equivalent units	32	52	100
Changes in market value of phantom units awarded to directors	(238)	430	461
Total deferred equity-based director compensation expense	$ 301	$ 917	$ 1,237

16. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. We manage our segments separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenues from affiliates and external customers, operating expenses, product purchases and equity earnings. We conduct transactions between our business segments on the same basis as transactions with third-party entities.

Management believes that investors benefit from having access to the same financial measures that they use. Operating margin, 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; however, we compute operating margin with components that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables. Operating profit includes expense items, such as depreciation and amortization expense and G&A cost that management does not consider when evaluating the core profitability of our operations.

Beginning in 2010, we transferred our East Houston, Texas terminal from our petroleum terminals segment to our petroleum pipeline system segment. We have increasingly utilized the East Houston terminal, which is an origin for our pipeline system, as a pipeline terminal. For instance, we have built a connection between the East Houston terminal and our Houston-to-El Paso pipeline section to serve as an origin for that pipeline. Further, we have constructed a pipeline connection from our East Houston terminal to a third-party pipeline near Houston, Texas to allow us to transport petroleum products from the Port Arthur, Texas refinery region into our pipeline markets. We are commercially managing the East Houston terminal in coordination with our pipeline to provide efficient marketing to our customers. At the beginning of 2010, we realigned this facility under petroleum pipeline management and have reported its operating results both internally and externally as part of that segment. We have adjusted the historical financial results for our segments to conform to the current period's presentation. The historical adjustments to revenues and expenses were not material and consolidated operating profit did not change because of this reclassification. The net book value of the asset transferred was approximately $79.0 million.

	Year Ended December 31, 2008				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 478,473	$138,717	$22,704	$(1,084)	$ 638,810
Product sales revenues	543,694	30,401	—	—	574,095
Affiliate management fee revenue	733	—	—	—	733
Total revenues	1,022,900	169,118	22,704	(1,084)	1,213,638
Operating expenses	195,262	59,126	14,044	(3,561)	264,871
Product purchases	429,294	8,279	—	(1,006)	436,567
Gain on assignment of supply agreement	(26,492)	—	—	—	(26,492)
Equity earnings	(4,067)	—	—	—	(4,067)
Operating margin	428,903	101,713	8,660	3,483	542,759
Depreciation and amortization expense	56,225	25,623	1,170	3,483	86,501
G&A expenses	52,874	17,313	3,115	—	73,302
Operating profit	$ 319,804	$ 58,777	$ 4,375	$ —	$ 382,956
Additions to long-lived assets	$ 177,302	$123,584	$ 5,536		$ 306,422
	As of December 31, 2008				
Segment assets	$1,772,779	$720,256	$38,561		$2,531,596
Corporate assets					69,112
Total assets					$2,600,708
Goodwill	$ 2,864	$ 11,902	$ —		$ 14,766
Equity investments	$ 23,190	$ —	$ —		$ 23,190

	Year Ended December 31, 2009				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 494,165	$166,950	$19,862	$(2,032)	$ 678,945
Product sales revenues	320,100	14,365	—	—	334,465
Affiliate management fee revenue	761	—	—	—	761
Total revenues	815,026	181,315	19,862	(2,032)	1,014,171
Operating expenses	180,979	64,349	16,196	(3,889)	257,635
Product purchases	275,880	6,393	—	(1,982)	280,291
Equity earnings	(3,431)	—	—	—	(3,431)
Operating margin	361,598	110,573	3,666	3,839	479,676
Depreciation and amortization expense	61,704	30,208	1,465	3,839	97,216
G&A expenses	60,846	20,859	2,344	—	84,049
Operating profit (loss)	$ 239,048	$ 59,506	$ (143)	$ —	$ 298,411
Additions to long-lived assets	$ 429,453	$ 88,878	$ 276		$ 518,607
	As of December 31, 2009				
Segment assets	$2,303,432	$787,068	$36,191		$3,126,691
Corporate assets					36,457
Total assets					$3,163,148
Goodwill	$ 2,864	$ 11,902	$ —		$ 14,766
Equity investments	$ 22,054	$ —	$ —		$ 22,054

	Year Ended December 31, 2010				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 583,977	$ 196,719	$14,922	$(2,019)	$ 793,599
Product sales revenues	744,612	18,750	—	(272)	763,090
Affiliate management fee revenue	758	—	—	—	758
Total revenues	1,329,347	215,469	14,922	(2,291)	1,557,447
Operating expenses	190,971	75,172	19,078	(3,009)	282,212
Product purchases	663,327	7,549	—	(2,291)	668,585
Equity earnings	(5,732)	—	—	—	(5,732)
Operating margin (loss)	480,781	132,748	(4,156)	3,009	612,382
Depreciation and amortization expense	69,758	34,446	1,455	3,009	108,668
G&A expenses	68,908	23,904	2,504	—	95,316
Operating profit (loss)	$ 342,115	$ 74,398	$ (8,115)	$ —	$ 408,398
Additions to long-lived assets	$ 315,583	$ 191,518	$ 2,384		$ 509,485

	As of December 31, 2010				
Segment assets	$2,630,586	$1,018,356	$35,731		$3,684,673
Corporate assets					33,227
Total assets					$3,717,900
Goodwill	$ 15,136	$ 24,789	$ —		$ 39,925
Equity investments	$ 22,934	$ 794	$ —		$ 23,728

The increase in segment assets from 2009 to 2010 resulted primarily from the business we acquired from BP and other acquisitions completed during 2010 (see Note 5—*Acquisitions*).

The increase in segment assets from 2008 to 2009 resulted primarily from the Houston-to-El Paso pipeline section acquired during third quarter 2009 (see Note 5—*Acquisitions*).

17. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $34.4 million and $32.8 million at December 31, 2009 and 2010, respectively. We have classified environmental liabilities as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that we will pay the expenditures associated with these environmental liabilities over the next 10 years. Environmental expenses recognized because of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expenses (credits) were $(1.4) million, $8.4 million and $11.8 million in 2008, 2009 and 2010, respectively. Environmental credits for 2008 included the impact of a favorable settlement of a civil penalty related to historical product releases, which resulted in the reduction of our environmental liability accrual by $12.1 million.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $3.9 million at December 31, 2009, of which we recorded $3.3 million and $0.6 million to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Receivables from insurance carriers related to environmental matters at December 31, 2010 were $2.2 million, of which $1.0 million and $1.2 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Amounts received from insurance carriers related to environmental matters during 2008, 2009 and 2010 were $0.8 million, $0.7 million and $2.8 million, respectively.

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, we do not recognize these net overages in our financial statements until we either sell the associated barrels or use them to offset future product losses. The net unrecognized product overages for our petroleum terminals operations had a market value of approximately $5.8 million as of December 31, 2010. However, the actual amounts we will recognize in future periods will depend on product prices at the time we either sell the associated barrels or use them to offset future product losses.

Other. We are a party to various other 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, will not have a material adverse effect on our financial position, results of operations or cash flows.

18. Quarterly Financial Data (unaudited)

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

2009	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$212,926	$208,220	$239,770	$353,255
Total costs and expenses	$157,385	$145,249	$166,380	$250,177
Operating margin	$100,348	$107,321	$119,373	$152,634
Net income	$ 41,170	$ 49,138	$ 54,215	$ 81,952
Net income allocated to limited partners' interest	$ 12,022	$ 14,611	$ 18,161	$ 81,952
Basic and diluted net income per limited partner unit	$ 0.30	$ 0.37	$ 0.43	$ 0.77
2010				
Revenues	$329,695	$423,060	$406,201	$398,491
Total costs and expenses	$244,577	$299,819	$325,604	$284,781
Operating margin	$135,891	$170,614	$133,278	$172,599
Net income	$ 64,534	$102,452	$ 56,637	$ 87,957
Net income allocated to limited partners' interest	$ 64,534	$102,520	$ 56,791	$ 88,132
Basic and diluted net income per limited partner unit	$ 0.60	$ 0.96	$ 0.51	$ 0.78

The acquisitions made in third quarter 2009 and third quarter 2010 (see Note 5–*Acquisitions*) favorably impacted our revenues and operating margins during 2010.

Unrealized losses on NYMEX agreements of $18.4 million unfavorably affected first quarter 2009 revenues and net income. Unrealized losses on NYMEX agreements of $19.1 million unfavorably affected second quarter 2009 revenues and net income. In September 2009, we completed the simplification of our capital structure, and as a result, we allocated all of our net income for fourth quarter 2009 and all of 2010 to our limited partners.

19. Fair Value Disclosures

Fair Value of Financial Instruments

We used the following methods and assumptions in estimating our fair value disclosure for financial instruments:

- *Cash and cash equivalents and restricted cash.* The carrying amounts reported in our consolidated balance sheets approximate fair value due to the short-term maturity or variable rates of these instruments.

- *Energy commodity derivatives deposits*. This asset represents a short-term deposit we paid associated with our energy commodity derivatives contracts. The carrying amount reported in our consolidated balance sheets approximates fair value as the deposits paid change daily in relation to the associated contracts
- *Long-term receivables.* Fair value was determined by estimating the present value of future cash flows using a risk- free rate of interest.
- *Energy commodity derivatives contracts*. These include NYMEX contracts related to petroleum products. These contracts are carried at fair value in our consolidated balance sheets and are valued based on quoted prices in active markets.
- *Debt.* We based the fair value of our publicly traded notes, excluding the value of interest rate swaps qualifying as fair value hedges, on the prices of those notes at December 31, 2009 and 2010. The carrying amount of borrowings under our revolving credit facility approximates fair value due to the variable rates of that instrument.
- *Interest rate swaps.* Fair value was determined based on an assumed exchange, at the end of each period; in an orderly transaction with the financial institution counterparties of the interest rate derivative agreements adjusted for the effect of credit risk (see Note 13–*Derivative Financial Instruments*). We calculated the exchange value using present value techniques on estimated future cash flows based on forward interest rate curves.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2009 and December 31, 2010 (in thousands):

	December 31, 2009		December 31, 2010	
Assets (Liabilities)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Cash and cash equivalents	$ 4,168	$ 4,168	$ 7,483	$ 7,483
Restricted cash	$ —	$ —	$ 14,379	$ 14,379
Energy commodity derivatives deposits	$ 17,943	$ 17,943	$ 22,302	$ 22,302
Long-term receivables	$ 618	$ 589	$ 1,167	$ 1,161
Energy commodity derivatives contracts (current)	$ (9,257)	$ (9,257)	$ (11,790)	$ (11,790)
Energy commodity derivatives contracts (noncurrent)	$ (1,146)	$ (1,146)	$ (4,920)	$ (4,920)
Debt	$(1,680,004)	$(1,777,064)	$(1,906,148)	$(2,048,895)
Interest rate swaps (current)	$ 4,446	$ 4,446	$ —	$ —
Interest rate swaps (noncurrent)	$ (1,649)	$ (1,649)	$ —	$ —

Fair Value Measurements

The following tables summarize the recurring fair value measurements of our NYMEX commodity contracts and interest rate swaps as of December 31, 2009 and December 31, 2010, based on the three levels established by ASC 820-10-50; Paragraph 2, *Fair Value Measurements and Disclosures-Overall-Disclosure* (in thousands):

		Asset Fair Value Measurements as of December 31, 2009 using:		
Assets (Liabilities)	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Energy commodity derivatives contracts (current)	$(9,257)	$(9,257)	$ —	$—
Energy commodity derivatives contracts (noncurrent)	$(1,146)	$(1,146)		
Interest rate swaps (current)	$ 4,446	$ —	$ 4,446	$—
Interest rate swaps (noncurrent)	$(1,649)	$ —	$(1,649)	

Assets (Liabilities)	Total	Asset Fair Value Measurements as of December 31, 2010 using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (current)	$(11,790)	$(11,790)	$ —	$ —
Energy commodity derivatives contracts (noncurrent)	$ (4,920)	$ (4,920)	$ —	$ —

20. Distributions

Distributions we paid during 2008, 2009 and 2010 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Limited Partner Units	General Partner (a)	Total Cash Distribution
2/14/2008	$0.65750	$ 43,884	$19,909	$ 63,793
5/15/2008	0.67250	44,885	20,910	65,795
8/14/2008	0.68750	45,886	21,911	67,797
11/14/2008	0.70250	46,887	22,912	69,799
Total	$2.72000	$181,542	$85,642	$267,184
2/13/2009	$0.71000	$ 47,537	$23,478	$ 71,015
5/15/2009	0.71000	47,537	23,478	71,015
8/14/2009	0.71000	47,537	23,478	71,015
11/13/2009	0.71000	75,677	—	75,677
Total	$2.84000	$218,288	$70,434	$288,722
2/12/2010	$0.71000	$ 75,779	$ —	$ 75,779
5/14/2010	0.72000	76,847	—	76,847
8/13/2010	0.73250	82,393	—	82,393
11/12/2010	0.74500	83,798	—	83,798
Total	$2.90750	$318,817	$ —	$318,817

(a) Includes amounts paid to MMP GP for its incentive distribution rights.

Distributions paid during 2008 and 2009 by Holdings to its limited partners prior to its dissolution at the completion of the simplification were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Limited Partner Units	General Partner	Total Cash Distribution
2/14/2008	$0.48538	$19,232	$ 3	$19,235
5/15/2008	0.50988	20,204	3	20,207
8/14/2008	0.53360	21,143	3	21,146
11/14/2008	0.55968	22,177	3	22,180
Total	$2.08854	$82,756	$ 12	$82,768
2/13/2009	$0.56759	$22,490	$ —	$22,490
5/15/2009	0.56759	22,490	—	22,490
8/14/2009	0.56759	22,490	—	22,490
Total	$1.70277	$67,470	$ —	$67,470

Total distributions paid were as follows (in thousands):

	Year Ended December 31,		
	2008	2009	2010
Cash distributions we paid	$267,184	$288,722	$318,817
Less distributions we paid to our general partner	85,642	70,434	—
Distributions we paid to outside owners	181,542	218,288	318,817
Cash distributions paid by Holdings to its outside owners	82,768	67,470	—
Total distributions	$264,310	$285,758	$318,817

21. Owners' Equity

Equity Offering

In July 2010, we completed a public offering of 5,750,000 of our common units at $46.65 per unit and received net proceeds of approximately $258.4 million after underwriting discounts of $9.5 million and offering expenses of $0.3 million. We used the combined net proceeds from this offering and our debt offering in August 2010 (see Note 12—*Debt*) to pay the $291.3 million purchase price for the business we acquired from BP (see Note 5—*Acquisitions*) plus approximately $53.0 million for associated crude oil tank bottoms that we acquired in October 2010 and to repay the outstanding balance of our revolving credit facility, which at that time was $175.5 million. The remaining amount of the net proceeds from these offerings was used for general partnership purposes.

Owners' Equity

The following table details the changes in the number of our limited partner units outstanding from January 1, 2008 through December 31, 2010.

Limited partner units outstanding on January 1, 2008	**66,546,297**
01/08—Settlement of 2005 award grants	196,856
01/08—Other[(a)]	577
Limited partner units outstanding on December 31, 2008	**66,743,730**
01/09—Settlement of 2006 and 2007 award grants	209,320
01/09—Other[(a)]	828
09/09—Additional awards issued in September 2009	10,000
09/09—Holdings units converted to MMP units[(b)]	39,623,944
Limited partner units outstanding on December 31, 2009[(c)]	**106,587,822**
01/10—Settlement of 2007 award grants	140,317
01/10—Other[(a)]	3,210
07/10—Issuance of common units	5,750,000
Limited partner units outstanding on December 31, 2010	**112,481,349**

(a) Limited partner units issued to settle the equity-based retainer paid to one of the independent directors of MMP GP.

(b) Pursuant to the simplification (see Note 2—*Summary of Significant Accounting Policies*), all of the outstanding limited partner units of Holdings converted into our limited partner units on September 28, 2009 at the exchange rate of 0.6325 to 1.0.

(c) The weighted average units outstanding reported on the consolidated statements of income were the pre-simplification outstanding limited partner units of Holdings and our post-simplification limited partner units outstanding, adjusted for director-earned phantom units and certain unvested LTIP awards whose performance metrics had been met.

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

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

- right to receive distributions of our available cash within 45 days after the end of each quarter;

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

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

Other Changes in Owners' Equity

Affiliate capital contributions were $3.7 million during the year ended December 31, 2008, which primarily consisted of payments Holdings received from MGG Midstream Holdings, L.P. which Holdings in turn reimbursed to us for costs incurred under the G&A cost cap agreement. Capital contributions during 2010 by a private investment group (non-controlling owners) in MCO, which we consolidate, were $14.7 million, which included cash contributions of $4.4 million and $10.3 million of non-cash contributions (see Note 1—*Organization and Description of Business*).

General Partner Transactions

In December 2008, Holdings acquired its general partner from MGG Midstream Holdings, L.P. Concurrent with that transaction, MGG Midstream Holdings, L.P. distributed all 5.6 million limited partner units it held in Holdings to its equity owners. Holdings did not issue additional limited partner units and it received no proceeds because of these transactions. Subsequent to that transaction, we no longer allocated Holdings GP a portion of Holdings' net income.

In September 2009, pursuant to the simplification, our general partner became our wholly owned subsidiary and no longer holds an economic interest in us.

22. Assignment of Supply Agreement

As part of our acquisition of a pipeline system in October 2004, we assumed a third-party supply agreement. Under this agreement, we were obligated to supply petroleum products to one of our customers until 2018. At the time of this acquisition, we believed that the profits we would receive from the supply agreement were below the fair value of our tariff-based shipments on this pipeline and we established a liability for the expected shortfall. On March 1, 2008, we assigned this supply agreement and sold related inventory of $47.6 million to a third party. Further, we returned our former customer's cash deposit, which was $16.5 million at the time of the assignment. During first quarter 2008, we obtained a full release from the supply customer; therefore, we had no future obligation to perform under this supply agreement, even in the event the third-party assignee was unable to perform its obligations under the agreement. As a result, we wrote off the unamortized amount of the liability and recognized a gain of $26.5 million in 2008.

23. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2010.

Non-recognizable events

On October 20, 2010, one of our executive officers, Richard A. Olson, senior vice president, Operations and Technical Services, announced his departure from the partnership effective March 1, 2011. Larry J. Davied was named senior vice president of Operations and Technical Services effective February 14, 2011, to replace the position vacated by Mr. Olson.

On January 27, 2011, the compensation committee approved 148,670 unit award grants pursuant to our long-term incentive plan. These award grants have a three-year vesting period that will end on December 31, 2013.

Effective January 31, 2011, our former chairman of the board, president and chief executive officer, Don R. Wellendorf, retired. Michael N. Mears, formerly our chief operating officer, was elected chairman of the board, president and chief executive officer of our general partner. Jeff Selvidge was named senior vice president of Transportation and Terminals effective February 14, 2011, and has assumed a number of the responsibilities formerly performed by Mr. Mears in his role as chief operating officer. 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 February 1, 2011, to assist in the transition of his duties and responsibilities on an as-needed basis and to provide other advisory and consulting services for consideration of $0.3 million and an agreement that his 2009 and 2010 phantom unit award grants that are performance based, a portion of which would otherwise have been forfeited as a result of his retirement, will not be forfeited. The payout of these awards will continue to be subject to the same financial performance metrics as originally established for 2009 and 2010 award grants. The fair value of these award grants on January 31, 2011 was $1.8 million.

On January 31, 2011, we issued 255,222 limited partner units, of which 252,746 were issued to settle the 2008 unit award grants to certain employees that vested on December 31, 2010 and 2,476 were issued to settle the equity-based retainer paid to two of the directors of our general partner.

On February 4, 2011, we acquired the private investment group's common equity in MCO for $40.5 million.

On February 8, 2011, we entered into a $50.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of our 6.40% notes due July 15, 2018.

On February 14, 2011, we paid cash distributions of $0.7575 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 7, 2011. The total distributions paid were $85.4 million.

Item 9. *Changes in and Disagreement With Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. There have been no changes in our internal control over financial reporting (as defined in Rule 13a—15(f) of the Securities Exchange Act) during the quarter ending December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. On September 1, 2010, we completed an acquisition of a business from BP Pipelines (North America), Inc. As permitted by the Securities and Exchange Commission, management has elected to exclude this acquisition from its assessment of the effectiveness of our internal control over financial reporting as of December 31, 2010. This acquired business represented approximately 10% of consolidated total assets and approximately 1% of consolidated total revenues as of and for the year ended December 31, 2010, respectively. See Note 5—*Acquisitions* to the accompanying consolidated financial statements for further discussion of this acquisition.

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

Management's Report on Internal Control Over Financial Reporting

See "Management's Annual Report on Internal Control Over Financial Reporting" set forth in Item 8, Financial Statements and Supplementary Data.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information regarding the directors and executive officers of our general partner and our corporate governance required by Items 401, 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be presented in our definitive proxy statement to be filed pursuant to Regulation 14A (our "Proxy Statement") under the following captions, which information is to be incorporated by reference herein:

- Director Election Proposal;
- Executive Officers of our General Partner;
- Section 16(a) Beneficial Ownership Reporting Compliance;
- Code of Ethics;
- Corporate Governance—Director Nominations; and
- Corporate Governance—Board Committees.

Item 11. *Executive Compensation*

The information regarding executive compensation required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Compensation of Directors and Executive Officers;
- Compensation Committee Interlocks and Insider Participation; and
- Compensation Committee Report.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information regarding securities authorized for issuance under equity compensation plans and security ownership required by Items 201(d) and 403 of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Securities Authorized for Issuance Under Equity Compensation Plans; and
- Security Ownership of Certain Beneficial Owners and Management.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information regarding certain relationships and related transactions and director independence required by Items 404 and 407(a) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Transactions with Related Persons, Promoters and Certain Control Persons; and
- Corporate Governance—Director Independence.

Item 14. *Principal Accountant Fees and Services*

The information regarding principal accountant fees and services required by Item 9(e) of Schedule 14A of the Securities Exchange Act of 1934 will be presented in our Proxy Statement under the caption "Independent Registered Public Accounting Firm," which information is to be incorporated by reference herein.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)1 and (a)2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a)3, (b) and (c). The exhibits listed below are filed as part of this annual report.

Exhibit No.	Description
Exhibit 2	
*(a)	Agreement Relating to Simplification of Capital Structure dated as of March 3, 2009 by and among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan Midstream Holdings, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 2.1 to Form 8-K filed March 4, 2009).
*(b)	Amendment No. 1 dated as of August 6, 2009 to the Agreement Relating to Simplification of Capital Structure dated as of March 3, 2009 by and among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan Midstream Holdings, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 2.1 to Form 8-K filed August 10, 2009).
Exhibit 3	
*(a)	Certificate of Limited Partnership of Magellan Midstream Partners, L.P. dated August 30, 2000, as amended on November 15, 2002 and August 12, 2003 (filed as Exhibit 3.1 to Form 10-Q filed November 10, 2003 (File No. 001-16335/03989347)).
*(b)	Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed September 30, 2009).
*(c)	Amended and Restated Certificate of Formation of Magellan GP, LLC dated November 15, 2002, as amended on August 12, 2003 (filed as Exhibit 3(f) to Form 10-K filed March 10, 2004 (File No. 001-16335/04660853)).
*(d)	Third Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated September 28, 2009 (filed as Exhibit 3.2 to Form 8-K filed September 30, 2009).
Exhibit 4	
*(a)	Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed September 30, 2009).
*(b)	Unit Purchase Rights Agreement dated as of December 4, 2008 between Magellan Midstream Partners, L.P. and Computershare Trust Company, N.A. (filed as Exhibit 4.1 to Form 8-A filed December 5, 2008).
*(c)	Amendment No. 1 dated as of March 3, 2009 to Unit Purchase Rights Agreement dated as of December 4, 2008 between Magellan Midstream Partners, L.P. and Computershare Trust Company, N.A. (filed as Exhibit 4.1 to Form 8-K filed March 4, 2009).
*(d)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004 (File No.001-16335/04829044)).
*(e)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004 (File No. 001-16335/04829044)).
*(f)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004 (File No. 001-16335/041080163)).

Exhibit No.	Description
*(g)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(h)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S.Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
*(i)	Second Supplemental Indenture dated as of July 14, 2008 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed July 14, 2008).
a*(j)	Third Supplemental Indenture dated as of June 26, 2009 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed June 26, 2009).
*(k)	Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed August 16, 2010).
*(l)	First Supplemental Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed August 16, 2010).
Exhibit 10	
(a)	Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated October 20, 2010.
(b)	Description of Magellan 2011 Annual Incentive Program.
(c)	Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2011.
*(d)	Director Deferred Compensation Plan effective October 1, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 4, 2006 (File No. 001-16335/061128415)).
*(e)	$550,000,000 Second Amended and Restated Credit Agreement dated as of September 20, 2007 among Magellan Midstream Partners, L.P., as Borrower, the Lenders party thereto and Wachovia Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to Form 8-K filed September 21, 2007).
*(f)	Amendment No. 1 dated as of December 4, 2009 to $550,000,000 Second Amended and Restated Credit Agreement dated as of September 20, 2007 among Magellan Midstream Partners, L.P., as Borrower, the Lenders party thereto and Wachovia Bank, N.A., as Administrative Agent (filed as Exhibit 10(f) to Form 10-K filed February 24, 2010).
*(g)	Amendment No. 2 dated as of September 17, 2010 to $550,000,000 Second Amended and Restated Credit Agreement dated as of September 20, 2007 among Magellan Midstream Partners, L.P., as Borrower, the Lenders party thereto and Wachovia Bank, N.A., as Administrative Agent (filed as Exhibit 10.5 to Form 10-Q filed November 2, 2010).
*(h)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004 (File No. 001-16335/04829044)).
*(i)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004 (File No. 001-16335/04829044)).
*(j)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004 (File No.001-16335/041080163)).
*(k)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(l)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
*(m)	Second Supplemental Indenture dated as of July 14, 2008 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed July 14, 2008).
*(n)	Third Supplemental Indenture dated as of June 26, 2009 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed June 26, 2009).
*(o)	Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed August 16, 2010).
*(p)	First Supplemental Indenture dated as of August 22, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed August 16, 2010).
*(q)	Unit Purchase Rights Agreement dated as of December 4, 2008 between Magellan Midstream Partners, L.P. and Computershare Trust Company, N.A. (filed as Exhibit 4.1 to Form 8-A filed December 5, 2008).
*(r)	Amendment No. 1 dated as of March 3, 2009 to Unit Purchase Rights Agreement dated as of December 4, 2008 between Magellan Midstream Partners, L.P. and Computershare Trust Company, N.A. (filed as Exhibit 4.1 to Form 8-K filed March 4, 2009).
*(s)	Asset Purchase Agreement dated as of June 18, 2009 between Longhorn Partners Pipeline, L.P. and Magellan Midstream Partners, L.P. (filed as Exhibit 10.1 to Form 8-K filed July 29, 2009).

Exhibit No.	Description
*(t)	IDR Entity Assumption Agreement dated September 28, 2009 by and among Magellan Midstream Partners, L.P., Magellan IDR LP, LLC and Magellan IDR, L.P. (filed as Exhibit 10.1 to Form 8-K filed September 30, 2009).
*(u)	Contribution and Assumption Agreement dated September 28, 2009 by and among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan Midstream Holdings, L.P., Magellan Midstream Holdings GP, LLC and MGG GP Holdings, LLC (filed as Exhibit 10.2 to Form 8-K filed September 30, 2009).
(v)	Form of 2011 Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
*(w)	Cushing and South Houston Asset Purchase Agreement by and between BP Pipelines (North America), Inc. and Magellan Pipeline Company, L.P. dated July 12, 2010 (filed as Exhibit 10.1 to Form 10-Q filed August 3, 2010).
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
(a)	Code of Ethics dated February 1, 2011 by Michael N. Mears, principal executive officer.
(b)	Code of Ethics dated February 1, 2011 by John D. Chandler, principal financial and accounting officer.
Exhibit 21	Subsidiaries of Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
(a)	Certification of Michael N. Mears, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
(b)	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101-INS	XBRL Instance Document.
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MAGELLAN MIDSTREAM PARTNERS, L.P.
(Registrant)

By: MAGELLAN GP, LLC, its general partner

By: /s/ JOHN D. CHANDLER

John D. Chandler
Senior Vice President
and Chief Financial Officer

Date: February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Title	Date
/s/ MICHAEL N. MEARS **Michael N. Mears**	Chairman of the Board and Principal Executive Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ JOHN D. CHANDLER **John D. Chandler**	Principal Financial and Accounting Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ WALTER R. ARNHEIM **Walter R. Arnheim**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ ROBERT G. CROYLE **Robert G. Croyle**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ PATRICK C. EILERS **Patrick C. Eilers**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ JAMES C. KEMPNER **James C. Kempner**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ JAMES R. MONTAGUE **James R. Montague**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011
/s/ BARRY R. PEARL **Barry R. Pearl**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 25, 2011

Index to Exhibits

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*(h)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004 (File No. 001-16335/04829044)).

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*(t)	IDR Entity Assumption Agreement dated September 28, 2009 by and among Magellan Midstream Partners, L.P., Magellan IDR LP, LLC and Magellan IDR, L.P. (filed as Exhibit 10.1 to Form 8-K filed September 30, 2009).
*(u)	Contribution and Assumption Agreement dated September 28, 2009 by and among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan Midstream Holdings, L.P., Magellan Midstream Holdings GP, LLC and MGG GP Holdings, LLC (filed as Exhibit 10.2 to Form 8-K filed September 30, 2009).
(v)	Form of 2011 Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long- Term Incentive Plan.
*(w)	Cushing and South Houston Asset Purchase Agreement by and between BP Pipelines (North America), Inc. and Magellan Pipeline Company, L.P. dated July 12, 2010 (filed as Exhibit 10.1 to Form 10-Q filed August 3, 2010).
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
(a)	Code of Ethics dated February 1, 2011 by Michael N. Mears, principal executive officer.
(b)	Code of Ethics dated February 1, 2011 by John D. Chandler, principal financial and accounting officer.
Exhibit 21	Subsidiaries of Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
(a)	Certification of Michael N. Mears, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
(b)	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101-INS	XBRL Instance Document.
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.