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, 2005

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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 common units held by non-affiliates computed by reference to the price at which the common units were last sold as of June 30, 2005 was $2,172,761,428.

As of March 1, 2006, there were 66,360,624 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2006 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

MAGELLAN MIDSTREAM PARTNERS, L.P.

FORM 10-K

PART I

ITEM 1. *Business*

(a) General Development of Business

We were formed as a limited partnership under the laws of the State of Delaware in August 2000. Our general partner is Magellan GP, LLC, which is a Delaware limited liability company. On September 1, 2003, our name changed from Williams Energy Partners L.P. (NYSE: WEG) to Magellan Midstream Partners, L.P. (NYSE: MMP). Magellan Midstream Holdings, L.P. (NYSE: MGG) has been the owner of our general partner since June 2003. Prior to June 2003, the owner of our general partner was The Williams Companies, Inc. ("Williams").

In March 2005, our general partner's board of directors approved a two-for-one split of our limited partner units. On April 12, 2005, holders of record at the close of business on April 5, 2005 received one additional limited partner unit for each limited partner unit owned on that date.

(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. Our asset portfolio currently consists of:

- an 8,500-mile petroleum products pipeline system, including 45 petroleum products terminals, serving the mid-continent region of the United States, which we refer to as our petroleum products pipeline system;
- seven petroleum products terminal facilities located along the United States Gulf and East Coasts, which we refer to as our marine terminals;
- 29 petroleum products terminals located principally in the southeastern United States, which we refer to as our inland terminals; and
- an 1,100-mile ammonia pipeline system serving the mid-continent region of the United States and six ammonia terminals.

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 and is comprised of a network of pipelines, terminals, storage facilities, tankers, barges, rail cars 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. Petroleum products transported, stored and distributed through our petroleum products pipeline system and petroleum products 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, aviation fuel, kerosene, distillates 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 # 6 fuel oil and vacuum gas oil; and
- *crude oil and condensate,* which are used as feedstocks by refineries.

The Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. According to the Energy Information Administration's "Petroleum Supply Annual for 2004", the Gulf Coast region accounted for approximately 44% of total U.S. daily refining capacity and 67% of U.S. refining capacity expansion from 1999 to 2004. 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, concentrated refineries. We expect this trend to continue in order to meet growing domestic and international demand. According to the Energy Information Administration's "Petroleum Supply Annual for 2004", the amount of petroleum products exported from the Gulf Coast region increased by approximately 30%, or 321 million barrels, from 1990 to 2004. The growth in refining capacity and increased product flow attributable to the Gulf Coast region has increased demand for transportation, storage and distribution facilities.

Description of Our Businesses

PETROLEUM PRODUCTS PIPELINE SYSTEM

In October 2004, we acquired a 2,000-mile petroleum products pipeline system. This strategic acquisition extended the reach of our existing pipeline system into key markets in Colorado and western and northern Texas. This pipeline system was already interconnected with our existing petroleum products pipeline in Oklahoma, thereby providing us with a direct connection to the Gulf Coast, which is the primary refining region of the United States and a major point of entry for foreign imports of refined petroleum products. As a result, our common carrier petroleum products pipeline system now extends 8,500 miles and covers a 13-state area, extending from Texas through the Midwest to Colorado, North Dakota, Minnesota and Illinois. Our pipeline system transports petroleum products and LPGs and includes 45 terminals. The products transported on our pipeline system are largely transportation fuels, and in 2005 were comprised of 54% gasoline, 36% distillates (which include diesel fuels and heating oil) and 10% LPGs and aviation fuel. Product originates 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. The petroleum products pipeline system segment accounted for 80%, 83% and 89% of our consolidated total revenues in 2003, 2004 and 2005, respectively. See Note 17—Segment Disclosures in the accompanying consolidated financial statements for financial information about the petroleum products pipeline system segment.

Our petroleum products pipeline system is dependent on the ability of refiners and marketers to meet the demand for refined petroleum products and LPGs in the markets it serves through their shipments on our pipeline system. According to statistics provided by the Energy Information Administration, the demand for refined petroleum products in the primary market areas served by our petroleum products pipeline system, known as Petroleum Administration for Defense District ("PADD") II, is expected to grow at an average rate of approximately 1.3% per year over the next 10 years. The total production of refined petroleum products from refineries located in PADD II is currently insufficient to meet the demand for refined petroleum products in PADD II. The excess PADD II 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 PADD III, which represents the Gulf Coast region.

Our petroleum products 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 the Explorer, CITGO and Seaway/ConocoPhillips pipelines. These connections to Gulf Coast refineries, together with our pipeline's extensive network throughout PADD II and connections to PADD II refineries, should allow us to accommodate not only demand growth, but also major supply shifts that may occur.

Our petroleum products pipeline system has experienced increased shipments over each of the last three years, with total shipments increasing by 22.6% from 2003 to 2005. The volume increases have come through our October 2004 petroleum products pipeline system acquisition as well as overall market demand growth, development projects on our system and incentive agreements with shippers utilizing our system. The operating statistics below reflect our petroleum products pipeline system's operations for the periods indicated:

	2003	2004	2005
Shipments (thousands of barrels):			
Refined products			
Gasoline	137,752	140,320	161,204
Distillates	78,264	89,614	106,137
Aviation fuel	13,691	16,709	21,792
LPGs	7,922	8,385	8,520
Total product shipments	237,629	255,028	297,653
Capacity leases	25,647	25,324	25,234
Total shipments, including capacity leases	263,276	280,352	322,887
Daily average (thousands of barrels)	721	766	885

The maximum number of barrels that our petroleum products pipeline system can transport per day depends upon the operating balance achieved at a given time between various segments on 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 products pipeline system, if necessary.

Operations. Our petroleum products pipeline system is the largest common carrier pipeline for refined petroleum products and LPGs in the United States in terms of pipeline miles. Through direct refinery connections and interconnections with other interstate pipelines, our system can access more than 40% of the refinery capacity in the continental United States. In general, we do not take title to the petroleum products we transport except with respect to a specific product supply agreement that we assumed in October 2004 and our petroleum products blending and fractionation operations.

Our petroleum products pipeline system generates approximately 80% of its revenue, excluding product sales revenues, through 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 a part of these tariffs are charges for terminalling and storage of products at 38 of our pipeline system's 45 terminals. Revenues from terminalling and storage at seven of our terminals are at privately negotiated rates.

Our petroleum products pipeline system generates the remaining 20% 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 unloading and loading, additive injection, laboratory testing and data services to shippers. Product services such as ethanol unloading and loading, additive injection, custom blending and laboratory testing are performed under a mix of "as needed", monthly and long-term agreements. We also receive fees for operating pipelines for others. In January 2004, we began serving as a subcontractor to an affiliate of

Williams for the operations of Longhorn Partners Pipeline, L.P., taking over as operator in April 2005, and in March 2004 we began operating the Osage Pipeline system.

Product sales revenues for the petroleum products pipeline primarily result from: (i) a third-party supply agreement assumed as part of the pipeline system we acquired in October 2004; and (ii) the sale of products that are produced from our petroleum products blending operation and from fractionating transmix. We take title to the products related to these activities, which subjects us to commodity price fluctuations that could significantly impact the gross margins we realize on the sales of these products. These activities benefited from high and increasing prices for refined petroleum products, as experienced in 2005. As a result, these activities generated significantly increased revenues and operating profit in the current year. Although the revenues generated from these activities were $107.6 million, $265.0 million and $625.7 million in 2003, 2004 and 2005, respectively, the difference between product sales and product purchases, which we believe better represents the importance of these activities, was $9.6 million, $15.9 million and $46.9 million in 2003, 2004 and 2005, respectively, as product purchases were $98.0 million, $249.1 million and $578.8 million in 2003, 2004 and 2005, respectively. Product sales revenues increased in 2005 over 2004 by $360.7 million primarily as a result of the third-party supply agreement we assumed with the assets acquired in October 2004.

Facilities. Our petroleum products pipeline system consists of an 8,500-mile pipeline with 45 terminals and includes more than 27.0 million barrels of aggregate usable storage capacity. The terminals deliver petroleum products primarily into tank trucks.

Petroleum Products Supply. Petroleum products originate from both refining and pipeline interconnection points along our pipeline system. In 2005, 51% of the petroleum products transported on our petroleum products pipeline system originated from 10 direct refinery connections and 49% originated from multiple interconnections with other pipelines. As set forth in the table below, our system is directly connected to, and receives product from, 10 operating refineries.

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
Coffeyville Resources	Coffeyville, KS
ConocoPhillips	Ponca City, OK
Flint Hills Resources (Koch)	Pine Bend, MN
Frontier Oil Corporation	El Dorado, KS
Gary Williams Energy Corp.	Wynnewood, OK
Marathon Ashland Petroleum Company	St. Paul, MN
Murphy Oil USA, Inc.	Superior, WI
Sinclair Oil Corp.	Tulsa, OK
Sunoco, Inc.	Tulsa, OK
Valero Energy Corp.	Ardmore, OK

The most significant of our pipeline connections is to Explorer Pipeline in Glenpool, Oklahoma, which transports product from the large refining complexes located on the Texas and Louisiana Gulf Coast. Our pipeline system is also connected to all Chicago area refineries through the West Shore Pipe Line.

As set forth in the table below, our system is connected to multiple pipelines.

Major Origins—Pipeline Connections (Listed Alphabetically)

Pipeline	Connection Location	Source of Product
BP	Manhattan, IL	Whiting, IN refinery
Cenex	Fargo, ND	Laurel, MT refinery
CITGO	Drumright, OK	Various Gulf Coast refineries
ConocoPhillips	Kansas City, KS	Various Gulf Coast refineries (via Seaway/Standish Pipeline); Borger, TX refinery
Explorer	Glenpool, OK; Mt. Vernon, MO	Various Gulf Coast refineries
Kaneb (Valero)	El Dorado, KS; Minneapolis, MN	Various OK & KS refineries; Mandan, ND refinery
Kinder Morgan	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
Sinco	East Houston, TX	Deer Park, TX refinery
Total (Valero)	Wynnewood, OK	Ardmore, OK refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries

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 these deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots and military and commercial jet fuel users. Propane 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. 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. These agreements have terms ranging from one to ten years. Approximately 58% of the shipments in 2005 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 products pipeline system.

For the year ended December 31, 2005, our petroleum products pipeline system had approximately 50 transportation customers. The top 10 shippers included several independent refining companies, integrated oil companies and one farm cooperative, and revenues attributable to these top 10 shippers for the year ended December 31, 2005 represented 33% of total revenues for our petroleum products pipeline system and 63% of revenues excluding product sales.

Product sales primarily relate to the third-party supply agreement we assumed in connection with the assets acquired in October 2004, as well as sales related to our petroleum products blending and fractionation operations to trading and marketing companies.

Markets and Competition. In certain markets, barge, truck or rail provide an alternative source for transporting refined 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 will agree 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.

PETROLEUM PRODUCTS TERMINALS

Within our petroleum products terminals network, we operate two types of terminals: marine terminals and inland terminals. Our marine terminals are located in close proximity to refineries and are large storage and distribution facilities that handle refined petroleum products, blendstocks, ethanol, heavy oils, feedstocks, crude oil and condensate. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as those operated by Colonial Pipeline Company ("Colonial"), Enterprise Products Partners L.P. ("Enterprise"), Plantation Pipe Line Company, Inc. ("Plantation") and TEPPCO Partners, L.P. ("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. The petroleum products terminals segment accounted for 17%, 15% and 10% of our consolidated total revenues in 2003, 2004 and 2005, respectively. See Note 17—Segment Disclosures in the accompanying consolidated financial statements for financial information about the petroleum products terminals segment.

Marine Terminals

We own and operate seven marine terminals, including five marine terminals located along the U.S. Gulf Coast. Our marine terminals are large storage and distribution facilities, with an aggregate storage capacity of approximately 21.0 million barrels, which provide inventory management, storage and distribution services for refiners and other large end-users of petroleum products.

Our marine 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 our marine terminals by all of those means as well as by truck and rail. Once the product has reached our marine terminals, we store the product for a period of time ranging from a few days to several months. Products that we store include refined petroleum products, blendstocks, crude oils, heavy oils and feedstocks. In addition to providing storage and distribution services, our marine terminals provide ancillary services including heating, blending and mixing of stored products and additive injection services.

Our marine terminals generate fees primarily through providing long-term or spot demand storage services and inventory management for a variety of customers. In general, we do not take title to the products that are stored in or distributed from our terminals. Refiners and chemical companies will typically use our marine 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 and inventory management to various industrial end-users, 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 2005, approximately 98% of our marine terminal capacity was utilized. As of December 31, 2005, approximately 90% of our usable storage capacity is under long-term contracts with remaining terms in excess of one year or that renew on an annual basis.

Markets and Competition. We believe that the continued strong demand for our marine terminals results from our cost-effective distribution services and key transportation links. We experience the greatest demand at our marine terminals in a "contango" market. A contango market condition exists when customers expect prices for petroleum products to be higher in the future. Under those conditions, customers tend to store more product to take advantage of the favorable pricing conditions expected in the future. When the opposite market condition known as "backwardation" exists, some companies choose not to store product or are less willing to enter into long-term storage contracts. The additional heating and blending services that we provide at our marine terminals attract additional demand for our storage services and result in increased revenue opportunities.

Several major and integrated oil companies have their own proprietary storage terminals along the Gulf Coast that are currently being used in their refining operations. If these companies choose to shut down their refining operations and elect to store and distribute refined petroleum products through their proprietary terminals, we would experience increased competition for the services that we provide. In addition, other companies have facilities in the Gulf Coast region that offer competing storage and distribution services.

Inland Terminals

We own and operate a network of 29 refined petroleum products terminals located primarily in the southeastern United States. We acquired six of these terminals in January 2004 and also acquired the remaining 21% ownership interest in eight terminals in which we previously had a 79% ownership interest. As a result, we wholly own 26 of the 29 terminals in our portfolio. Our terminals have a combined capacity of almost 6.0 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. During 2005, gasoline represented approximately 59% of the product volume distributed through our inland terminals, with the remaining 41% consisting of distillates.

Our inland terminals typically consist of multiple storage tanks that are connected to a third-party pipeline system. We load and unload products through an automated system that allows products to move directly from the common carrier pipeline to our storage tanks and directly from our storage tanks to a truck or rail car loading rack.

We are an independent provider of storage and distribution services. Because we generally do not own the products moving through our terminals, we are not exposed to the risks of product ownership. We operate our inland terminals as distribution terminals and we primarily serve 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.

We generate revenues by charging our customers a fee based on the amount of product that 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 rail car. In addition to throughput fees, we generate revenues by charging our customers a fee for injecting additives into gasoline, diesel and aviation fuel, and for filtering jet fuel.

Customers and Contracts. When we acquire terminals, we generally enter into long-term throughput contracts with the sellers under which they agree to continue to use the facilities. In addition to these agreements, we enter into contracts with new customers that typically last for one year with a continuing one-year renewal provision. Most of these contracts contain a minimum throughput provision that obligates the customer to move a minimum amount of product through our terminals or pay for terminal capacity reserved but not used. 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, 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, an important element for maintenance of high crop yields. Ammonia is the primary feedstock for the production of upgraded nitrogen fertilizers and chemicals. The ammonia pipeline system segment accounted for 3%, 2% and 1% of our consolidated revenues in 2003, 2004 and 2005, respectively. See Note 17—Segment Disclosures in the accompanying consolidated financial statements for financial information about the ammonia pipeline system segment.

Operations. We generate more than 90% of our ammonia pipeline system revenues through transportation tariffs. These tariffs are "postage stamp" tariffs, which means that each shipper pays a defined rate per ton of ammonia shipped regardless of the distance that ton of ammonia travels on our pipeline. In addition to transportation tariffs, we also earn revenue 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. A third-party pipeline company provides the operating services and a portion of the general and administrative ("G&A") services for our ammonia pipeline system under an operating agreement with us.

Facilities. Our ammonia pipeline is one of two ammonia pipelines operating in the United States and has a maximum annual delivery capacity of approximately 900,000 tons. Our ammonia pipeline system originates at production facilities in Borger, Texas, Verdigris, Oklahoma and Enid, Oklahoma and terminates in Mankato, Minnesota. We transport ammonia to 13 delivery points along our ammonia pipeline system, including six terminals which we own. The facilities at these points provide our customers with the ability to deliver ammonia to distributors who sell the ammonia to farmers and to store ammonia for future use. These facilities also provide our customers with the ability to remove ammonia from our pipeline for distribution to upgrade facilities that produce complex nitrogen compounds.

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. Our previous transportation agreements expired on June 30, 2005. We have entered into new agreements with our three customers which became effective July 1, 2005 and extend through June 2008. Each transportation contract contains a ship or pay mechanism whereby each customer has committed a tonnage that it expects to ship. Aggregate annual commitments from our customers for the period July 1, 2005 through June 30, 2006 are 525,000 tons. If a customer fails to ship its annual commitment, that customer must pay for the pipeline capacity it did not use.

Markets and Competition. Demand for nitrogen fertilizer has typically followed a combination of weather patterns and 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.

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 Valero L.P., which originates on the Gulf Coast and transports domestically produced and imported ammonia.

Major Customers

The percentage of revenues derived by customers that accounted for 10% or more of our consolidated total revenues is provided in the table below. Customer A is a customer of both our petroleum products pipeline system and petroleum products terminals segments. Customer B is a customer of our petroleum products pipeline system segment that purchases petroleum products from us pursuant to a third-party supply agreement we assumed in connection with our pipeline system acquisition in October 2004. We use letters of credit and cash deposits from these customers to mitigate credit exposure.

	2003	2004	2005
Customer A	27%	19%	9%
Customer B	0%	13%	42%
Total	27%	32%	51%

Tariff Regulation

Interstate Regulation. Our petroleum products pipeline system's interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate oil pipeline rates 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 products pipeline system, are currently regulated by FERC primarily through an index methodology, which in its initial form allowed a pipeline to change its rates based on the annual change in the producer price index for finished goods ("PPI-FG") less 1%. As required by its own regulations, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing rate indexing methodology. In December 2000, the FERC issued an order concluding that the rate index reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), the FERC changed the rate indexing methodology to the PPI-FG, but without the subtraction of 1% as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2001. The FERC is currently undertaking its five-year review of the indexing methodology, and in July 2005 issued a Notice of Inquiry proposing to continue using the PPI-FG, without adjustment, as the index for oil pipeline rate changes in the next five year period, commencing July 1, 2006. The FERC has not yet issued a decision related to this Notice of Inquiry.

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 products 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 or through an agreement between a shipper and the pipeline company that a rate is acceptable. Approximately 60% of our petroleum products pipeline system's markets are deemed competitive by the FERC, and we are allowed to charge market-based rates in these markets.

In July 2004, the D.C. Circuit issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld, among other things, the FERC's determination that certain rates of an interstate petroleum products pipeline, SFPP, L.P. ("SFPP"), were grandfathered rates under the Energy Policy Act of 1992 and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC's decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. 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 the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issues in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income tax allowance. Further, in the December 2005 order, the FERC concluded that for tax allowance purposes, the FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal rate of 28%. The FERC indicated that it would address the income tax allowance issues further in the context of SFPP's compliance filing due February 28, 2006. The FERC's *BP West Coast* remand decision, the new tax allowance policy and the December 2005 order have been appealed to the D.C. Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service.

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 holds market power, then we may be required to show that our rates are reasonable.

Intrastate Regulation. Some shipments on our petroleum products pipeline system move within a single state and thus are considered to be intrastate commerce. Our petroleum products 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 products 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.

Maintenance and Safety Regulations

We believe our assets are operated and maintained in material compliance with applicable federal, state and local laws and regulations, and in accordance with other generally accepted industry standards and practices.

Our assets are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard and comparable state statutes 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.

Our pipeline systems are also 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.

In December 2000, the Department of Transportation adopted new regulations requiring 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. Through December 31, 2005, we have spent approximately $43.6 million relative to system integrity assessments. These cost estimates could increase in the future if additional safety measures are required.

In 2003, the seller of the pipeline and terminal assets we acquired in October 2004 entered into a consent decree with the Environmental Protection Agency (“EPA”) arising out of a June 1999 incident unrelated to the assets we acquired. In order to resolve its civil liability for the incident, the seller agreed to pay civil penalties and to comply with certain terms set out in the consent decree. These terms include requirements for testing and maintenance of a number of the seller’s pipelines, including certain of the pipelines we acquired, the creation of a damage prevention program, submission to independent monitoring and various reporting requirements. The consent decree extends until 2008. Under our purchase agreement, we agreed, at our own expense, to complete any remaining remediation work required under the consent decree with respect to these pipelines and assumed a liability of approximately $8.6 million at the time of the acquisition for this remediation work. As of December 31, 2005, the remaining liability associated with this consent decree was $5.6 million. The seller has retained responsibility to the EPA for compliance with the terms of the consent decree.

Our marine terminals 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.

Environmental

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. This body of laws and regulations regulates many aspects of our business including 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. As an owner or lessee and operator of these facilities, we comply with federal, state and local laws and regulations.

Estimates provided below 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 only, and we cannot predetermine whether the actual total remediation costs will exceed estimated amounts. Except as may be disclosed below, we are not aware of any potential claims by third parties that could be materially adverse to our results of operations, financial position or cash flow.

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 and promptly detect and address releases is an integral part of our operations, damages and liabilities arising out of any future environmental release from our assets have the potential to have a material adverse effect on our financial position, cash flow and results of operations.

Environmental Indemnification Settlement. Prior to May 27, 2004, Williams had agreed to indemnify us against certain environmental losses, among other things, associated with assets that Williams contributed to us at the time of our initial public offering or which we subsequently acquired from Williams. In May 2004, we and our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from these indemnifications. Under this agreement, we received $35.0 million and $27.5 million from Williams on July 1, 2004 and 2005, respectively, and expect to receive installment payments from Williams of $20.0 million and $35.0 million on July 1, 2006 and 2007, respectively.

While the settlement agreement releases Williams from its environmental and certain indemnifications, other indemnifications remain in effect. These remaining indemnifications cover:

- Issues involving employee benefits matters;
- Issues involving rights-of-way, easements and real property, including asset titles; and
- Unlimited losses and damages related to tax liabilities.

As of December 31, 2004 and 2005, known liabilities that would have been covered by Williams' previous indemnity agreements were $40.8 million and $43.1 million, respectively. Through December 31, 2005, we have spent $17.4 million of the $117.5 million indemnification settlement amount for indemnified matters, including $6.6 million of capital costs. The cash we have received from the indemnity settlement is not reserved and has been used by us for our various other cash needs, including expansion capital spending.

Environmental Liabilities. Recorded estimated environmental liabilities were $60.8 million and $58.2 million at December 31, 2004 and 2005, respectively. These liabilities are provided on an undiscounted basis and have been classified as current or non-current based on estimates regarding the timing of actual payments, which are expected to occur over the next 10 years. Our liabilities include:

- In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to Williams based on a preliminary determination that Williams may have systematic problems with petroleum discharges from Magellan Pipeline operations. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases were violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention, Control and Countermeasure ("SPCC") requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these spills if the EPA were to successfully seek and obtain injunctive relief. We have submitted all information requested to date. We have met with the EPA and the DOJ and anticipate negotiating a final settlement with both agencies in 2006. We have accrued an amount that is less than $22.0 million associated with this matter. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows;
- During the second quarter of 2005, we experienced a line break and release of approximately 2,900 barrels of product on our petroleum products pipeline near our Kansas City, Kansas terminal. As of December 31, 2005, we have estimated the costs associated with this release of approximately $2.7 million. We have spent $1.7 million on remediation associated with this release and have $1.0 million of environmental liabilities recorded at December 31, 2005. In 2005, we received an information request from the EPA and from the Office of Pipeline Safety regarding this release. We have submitted all information requested on a timely basis. We have not been assessed a penalty by the EPA, or any other regulatory agency, relative to this release and we are unable to estimate with any certainty what penalties, if any, might be assessed. Therefore, our environmental accrual for this matter, as of December 31, 2005, includes no amounts for penalties. If penalties are assessed, they could be material to our results of operations and cash flows: and
- Estimated environmental liabilities recorded as a part of our known incidents.

Other Environmental Matters. In January 2006, we experienced a line break and release of approximately 3,200 barrels of gasoline from our petroleum products pipeline near Independence, Kansas. We are in the process of remediating the impacts from the release. We are also evaluating the estimated repair and remediation costs associated with the release. Our insurance coverage for this incident has a deductible of $1.5 million. We are unable to estimate with any degree of certainty what penalties, if any, might be assessed by the EPA or other governmental agency relative to this release. Penalties are not covered by our insurance policy. Our costs for repair, remediation and damages plus any penalties that may be assessed are not currently ascertainable and could have a material effect on our results of operations or cash flows.

In order to comply with EPA requirements related to ultra low sulfur diesel, some of which become effective in 2006, we will likely incur approximately $16.0 million to $18.0 million in capital costs. We will attempt either to recover certain of these costs through a surcharge added to our transportation rates or through a cost-of-service filing with respect to the rates for markets in which we have not been permitted to charge market-based rates. We may not be successful in our efforts to recover these costs. Further, should we attempt to recover these costs through a cost-of-service filing, customers or the FERC could challenge any aspect of our cost of service.

We have evaluated the SPCC regulations for potential deficiencies at our petroleum products terminals and are in the process of implementing corrective actions associated with identified potential deficiencies. We have estimated the capital liability associated with the corrective actions to be approximately $15.0 million with spending to occur through 2007.

Environmental Receivables. In June 2003, MGG assumed a $21.9 million obligation to indemnify us for certain identified environmental liabilities. As of December 31, 2005, we had received $15.2 million from MGG associated with this indemnification, resulting in a remaining associated receivable from MGG of $6.7 million. Environmental receivables from insurance carriers were $2.1 million at December 31, 2005.

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 to cover pre-existing unknown conditions on the majority of our petroleum products pipeline system. In conjunction with acquisitions, we generally purchase pollution legal liability insurance to cover pre-existing unknown conditions for the acquired assets.

Hazardous Substances and Wastes. In most instances, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into water or soils, and include measures to control pollution of the environment. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, 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.

In 2003, we received notice from the EPA that we were a potentially responsible party for a federal superfund site. We also received notice in 2003 from the Texas Commission on Environmental Quality ("TCEQ") regarding possible status as a potentially responsible party for a site undergoing a state superfund evaluation. We have responded to both correspondences indicating that neither Williams nor we have any documentation or knowledge of being a potentially responsible party at either site. We have subsequently responded to a request from the EPA received in December 2004 seeking additional data regarding the federal superfund site, indicating that we have found no information regarding the site. The TCEQ has not responded to us regarding the other site.

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 do not hold ourselves out as 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, including many oil and gas exploration and production wastes, from being subject to hazardous waste requirements, 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 have a material adverse effect on 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 have been 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. Although potential costs associated with the removal or remediation of previously disposed wastes are unknown, we do not expect these potential costs to have a material adverse effect on our results of operations, financial position or cash flows.

Above Ground Storage Tanks. States in which we operate typically have laws and regulations governing above ground tanks containing liquid substances. Generally, these laws and regulations require that these tanks include secondary containment systems or that the operators take alternative precautions to ensure that no contamination results from any leaks or spills from the tanks. The Department of Transportation Office of Pipeline Safety has incorporated American Petroleum Institute Standard No. 653 to regulate above ground tanks subject to their jurisdiction. 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 by us. However, we do not expect the costs associated with this increased handling to be significant. We believe that the future implementation of above ground storage tank laws or regulations will not have a material adverse effect on our results of operations, financial position or cash flows.

Water Discharges. Our operations can result in the discharge of pollutants, including oil. The Oil Pollution Act was enacted in 1990 and amends 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 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 spill is 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 upon us. States in which we operate have also enacted similar laws. Regulations have been or are being developed under the Oil Pollution Act, as well as comparable state laws that may also impose additional regulatory burdens on our operations. Although the costs associated with complying with the amended regulations cannot be determined at this time, we do not expect these expenditures to have a material adverse effect on our results of operations, financial position or cash flows.

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 noncompliance 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 exceeded permit discharges at some of our terminals, we do not expect our non-compliance with existing permits and foreseeable new permit requirements to have a material adverse effect on our results of operations, financial position or cash flows.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state and local laws. Under such laws, permits are typically required to emit pollutants into the atmosphere. Pursuant to the Clean Air Act and a 2003 consent decree, the EPA is required by no later than October 2006 to propose a rule relating to certain gasoline distribution facilities that is generally known as the Generally Available Control Technology Rule for Area Sources. Although we cannot currently determine the applicability of this anticipated rule to our assets, the final rule, when enacted, will likely require us to incur some level of capital expenditures for our terminals in order to be compliant. The anticipated rule also is expected to affect industries other than gasoline distribution terminals. Under EPA and applicable state and local regulations, our facilities that emit volatile organic compounds or nitrogen oxides are subject to increasingly stringent regulations, including requirements that some sources install maximum achievable control technology or reasonably available control technology. In addition, the regulations include an operating permit for major sources of volatile organic compounds, which applies to some of our facilities. We believe that we currently hold or have applied for all necessary air permits. Although we can give no assurances, we believe implementation of the 1990 Clean Air Act amendments and any changes to the state implementation plans pertaining to air quality in regional non-attainment areas will not have a material adverse effect on our results of operations, financial position or cash flows.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property, and in some instances, these rights-of-way 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 lands necessary for our pipelines. The previous owners of the applicable pipelines may not have commenced or concluded eminent domain proceedings for some rights-of-way.

Some of the leases, easements, rights-of-way, permits and licenses that have been transferred to us will require the consent of the grantor to transfer 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 affiliates of Williams for (1) title defects to our ammonia pipeline that arise before February 2016 and (2) title defects related to the portion of our petroleum products 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 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

Magellan Midstream Holdings GP, LLC ("MGG GP") employs various personnel who are assigned to conduct our operational and administrative functions. At December 31, 2005, MGG GP employed approximately 1,029 employees, of whom 545 conduct the operations of our petroleum products pipeline system, 227 conduct the operations of our petroleum products terminals and 257 provide G&A services.

(d) Financial Information About Geographical Areas

We have no revenue or segment profit or loss attributable to international activities.

(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.

You can also obtain information about us at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005 or at the New York Stock Exchange's ("NYSE") internet site (www.nyse.com). The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The chief executive officer of our general partner submitted an unqualified annual written certification to the NYSE in 2005 as required.

Our internet address is www.magellanlp.com. We make available free of charge on or through our internet site 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*

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, including payments to our affiliates.

The amount of cash we can distribute on our common 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.

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 in our pipeline, store at our marine terminals and distribute through our inland terminals, and thereby reduce our cash flow and our ability to pay cash distributions. Factors that could lead to a decrease in market demand include:

- an increase in the market price of petroleum products, which may reduce demand for gasoline and other petroleum products. Market prices for petroleum products are subject to wide fluctuation in response to changes in global and regional supply over which we have no control;
- a recession or other adverse economic condition that results in lower spending by consumers and businesses on transportation fuels such as gasoline, aviation fuel and diesel;
- higher fuel taxes or other governmental or regulatory actions that increase the cost of gasoline;
- 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
- the government–mandated increase in the use of alternative fuel sources, such as fuel cells and solar, electric and battery-powered engines.

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 weather-related or other natural causes, ruptures, leaks and fires. 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 incident to our business. In addition, as a result of market conditions, premiums for our insurance policies could increase significantly. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist and sabotage acts. If a significant accident or event occurs that is not fully insured, it could adversely affect our financial position, results of operations or cash flows and our ability to pay cash distributions.

Fluctuations in prices of refined petroleum products and natural gas liquids could materially affect our earnings.

A third-party supply agreement we assumed in connection with the acquisition of certain pipeline and terminal assets during October 2004 requires that we purchase and maintain certain inventories of petroleum products. In addition, we maintain product inventory related to our petroleum products blending and fractionation operations. Significant fluctuations in market prices of petroleum products could result in losses from these operations, thereby reducing the amount of cash we generate and our ability to pay cash distributions.

Rate regulation or a successful challenge to the rates we charge on our petroleum products pipeline system may reduce the amount of cash we generate.

The FERC regulates the tariff rates for interstate movements on our petroleum products 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 rates that were in excess of a just and reasonable level when taking into consideration our pipeline system's cost of service. In addition, shippers may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper 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 interstate markets. The indexing method allows a pipeline to increase its rates by a percentage equal to the change in the PPI-FG to the new ceiling level. If the PPI-FG falls, we could be required to reduce our rates that are based on the FERC's price indexing methodology if they exceed the new maximum allowable rate. The FERC's indexing methodology is subject to a five-year review, and in July 2005, the FERC issued a Notice of Inquiry proposing to continue using the PPI-FG, without adjustment, as the index for oil pipeline rate changes in the next five year period, commencing July 1, 2006. The FERC has not yet issued a decision in this matter. If the FERC continues its policy of using the PPI-FG, changes in the PPI-FG might not fully reflect actual increases in the costs associated with the pipelines subject to indexing, which would impair our ability to recover costs associated with our cost-of-service based rates.

The potential for a challenge to our indexed rates creates the risk that the FERC might find some of our indexed rates to be in excess of a just and reasonable level—that is, a level justified by our cost of service. In such an event, the FERC would order us to reduce any such rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

In July 2004, the D.C. Circuit issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld, among other things, the FERC's determination that certain rates of an interstate petroleum products pipeline, SFPP, were grandfathered rates under the Energy Policy Act of 1992 and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC's decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. 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 the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issues in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income allowance. Further, in the December 2005 order, the FERC concluded that for tax allowance purposes, the FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal rate of 28%. The FERC indicated that it would address the income tax allowance issues further in the context of SFPP's compliance filing due February 28, 2006. The FERC's *BP West Coast* remand decision, the new tax allowance policy and the December 2005 order have been appealed to the D.C. Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service.

We establish rates in approximately 60% of our interstate 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 successfully challenged, the FERC could take away our ability to establish market-based rates. We would then be required to establish rates that would be justified 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, change in the treatment of income tax allowances or payment of reparations could have a material adverse effect on our results of operations and reduce the amount of cash we generate.

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

We face competition from other pipelines and terminals in the same markets as our assets, as well as from other means of transporting, storing and distributing petroleum products, including from other pipeline systems, terminal operators and integrated refining and marketing companies that own their own terminal facilities. Our customers demand delivery of products on tight time schedules and in a number of geographic markets. If our quality of service declines or we cannot meet the demands of our customers, they may utilize the services of our competitors.

When prices for the future delivery of petroleum products that we store in our marine terminals fall below current prices, customers may be less likely to store these products, thereby reducing our storage revenues.

This market condition is commonly referred to as "backwardation." When the petroleum products market is in backwardation, the demand for storage capacity at our facilities may decrease. If the market becomes strongly backwardated for an extended period of time, the cash flows generated by our marine terminal facilities may be reduced, impacting our ability to pay cash distributions.

Our business is subject to federal, state and local laws and regulations that govern the environmental and operational safety aspects of our operations.

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 products 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.

In addition, we own or lease a number of properties that have been used for many years to distribute or store petroleum products by third parties not under our control. In some cases, predecessor owners, tenants or other users of these properties have disposed of or released hydrocarbons or solid wastes on or under these properties. Further, the transportation of ammonia by our pipeline is hazardous and may result in environmental damage, including accidental releases that may cause death or injuries to humans and farm animals and damage to crops.

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

We depend on connections with refineries and petroleum products 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 flow and ability to pay cash distributions.

The closure of mid-continent refineries that supply our petroleum products pipeline system could result in disruptions or reductions in the volumes we transport and the amount of cash we generate.

The EPA has adopted requirements that require refineries to install equipment to lower the sulfur content of gasoline and some diesel fuel they produce. The requirements relating to gasoline took effect in 2004, and the requirements relating to diesel fuel will take effect in 2006 and be implemented through 2010. If refinery owners that use our petroleum pipeline system determine that compliance with these new requirements is too costly, they may close some of these refineries, which could reduce the volumes transported on our petroleum products pipelines and the amount of cash we generate.

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 reduce our ability to pay cash distributions.

The pipeline and terminal assets we acquired in October 2004 are subject to a consent decree with the EPA and we could incur substantial costs and liabilities to comply with this decree that are not covered by the seller's indemnification of us.

In 2003, the seller of the pipeline and terminal assets we acquired in October 2004 entered into a consent decree with the EPA arising out of a June 1999 incident unrelated to the assets we acquired. In order to resolve its civil liability for the incident, the seller agreed to pay civil penalties and to comply with certain terms set out in the consent decree. These terms include requirements for testing and maintenance of a number of the seller's pipelines, including certain of the pipelines we acquired, the creation of a damage prevention program, submission to independent monitoring and various reporting requirements. The consent decree imposes penalties for non-compliance for a period of at least five years from the date of the consent decree. Under our purchase agreement, we agreed, at our own expense, to complete any remaining remediation work required under the consent decree with respect to these pipelines and assumed a liability of approximately $8.6 million at the time of the acquisition for this remediation work. The seller has agreed to retain responsibility under the consent decree for any ongoing independent monitoring obligations with respect to one of these pipelines.

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 capital or the incurrence of 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.

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 and transport.

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 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.

Our business is subject to federal EPA requirements that will lower the level of sulfur in diesel fuels beginning in June 2006.

Beginning in June 2006, the allowable level of sulfur in on-road and off-road diesel fuel will begin to be lowered to levels substantially below current specifications. This transition will require us to invest substantial amounts of capital and incur new operating costs that we may not be able to recover through increased revenues. This transition may require us to transfer low sulfur products to higher sulfur products within our system as a result of product contaminations, which could also lead to higher costs. To date, limited testing opportunities have been available for us to ensure that our transition plan will be successful due to the lack of product meeting the new low sulfur specifications.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the United States 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.

Our ammonia pipeline system is dependent on three customers.

Three customers ship all of the ammonia on our pipeline and utilize our six terminals. We have contracts with these three shippers that expire on June 30, 2008 and obligate them to ship-or-pay for specified minimum quantities of ammonia. The loss of any one of these three customers or their failure or inability to pay us could adversely affect our cash flows.

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.

Rising short-term interest rates could increase our financing costs and reduce the amount of cash we generate.

As of December 31, 2005, we had fixed-rate debt of $786.9 million outstanding, excluding unaccreted discounts and fair value adjustments for interest rate hedges. We have effectively converted $350.0 million of this debt to floating-rate debt using interest rate swap agreements. In addition, we had $13.0 million of floating rate borrowings outstanding on our revolving credit facility as of December 31, 2005. As a result of these swap agreements and revolver borrowings, we have exposure to changes in short-term interest rates. Based on the amounts outstanding on December 31, 2005, if LIBOR were to change by 0.25%, our annual interest expense would change by $0.9 million. Rising short-term rates could reduce the amount of cash we generate and adversely affect our ability to pay cash distributions.

The terms of our indemnification settlement agreement require Williams to make payments to us over the next two years, exposing us to credit risk.

In May 2004, our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from its environmental and certain other indemnification obligations to us, consisting primarily of costs related to environmental remediation matters related to assets that were contributed to us by Williams or which we acquired from Williams. We have received $62.5 million from Williams as of December 31, 2005, and we expect to receive the remaining balance in annual installments of $20.0 million and $35.0 million in July of 2006 and 2007, respectively. As of December 31, 2005, known liabilities that would have been covered by these indemnifications were $43.1 million. Williams' credit ratings are below investment grade. Failure of Williams to perform on its payment obligations under the settlement agreement could adversely affect our ability to meet these obligations and pay cash distributions.

Restrictions contained in our debt instruments and the debt instruments of Magellan Pipeline may limit our financial flexibility.

We and our subsidiary, Magellan Pipeline, 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. In addition, a change in control of our general partner could, under certain circumstances, result in our debt or the debt of Magellan Pipeline becoming due and payable.

Risks Related to Our Partnership Structure

In connection with its acquisition of our general partner in June 2003, MGG entered into a new omnibus agreement, which, among other things, caps our cash G&A expenses. A change in control of MGG or our general partner could increase our G&A expenses.

We are a third-party beneficiary of an omnibus agreement with MGG. There are limitations on the amount of G&A expenses for which we are required to reimburse MGG and certain of its affiliates, which operate as follows:

- for expenses below a lower cap amount, MGG and its affiliates are not required to make any reimbursements to us;
- for expenses above the lower cap amount and below an upper cap amount, MGG or its affiliates are required to reimburse us. During 2005, we were reimbursed $3.3 million for G&A expenses; and
- for expenses above the upper cap amount, MGG and its affiliates are not required to make any reimbursements to us.

The lower cap amount escalates annually at 7.0% (or, if greater, the percentage increases in the consumer price index). The upper cap amount escalates annually at the lesser of 2.5% or the percentage increase in the consumer price index. The upper and lower caps are further adjusted for incremental G&A expenses associated with acquisitions we consummate.

These limitations on our obligation to reimburse MGG and certain of its affiliates for G&A expenses will terminate upon a change in control of MGG or our general partner. A change in control of our general partner will be deemed to occur if, among other things, directors are elected whose nomination for election to our general partner's board of directors was not approved by our general partner or its board of directors or any nominating committee thereof at a time when the board was comprised of only such approved directors or the current directors. In the event of a change in control, the amount of cash we generate will be reduced by any G&A expenses we incur above the lower cap as a result of our becoming liable for the full amount of G&A expenses.

Termination of our services agreement with MGG GP could result in increased costs and limit our ability to meet our obligations and pay cash distributions.

We have entered into a services agreement with MGG GP, the general partner of MGG. The services provided under that agreement include the personnel necessary to perform our operations as well as accounting, building administration, human resources, information technology, legal, security and others. MGG GP has the right to terminate its obligations under this services agreement upon 90 days notice. To the extent that neither MGG GP nor any of its subsidiaries, including MGG and our general partner, provides these services to us, the limitations under the new omnibus agreement on our reimbursement of G&A expenses relating to these services would no longer apply and we may incur increased G&A expenses, which could increase our costs and limit our ability to meet our obligations and pay cash distributions.

Cost reimbursements due our general partner may be substantial and could reduce our cash available for distribution.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including officers and directors of our general partner, for expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions. Our general partner has sole discretion to determine the amount of its expenses which must be reimbursed, subject to certain annual limits. In addition, our general partner and its affiliates may provide us other services for which we will be charged fees as determined by our general partner.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner 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 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.

Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner and its affiliates have limited fiduciary duties to us and our unitholders, which may permit them to favor their own interests to the detriment of us and our unitholders.

Conflicts of interest may arise among our general partner and it affiliates, including MGG, on the one hand, and us and our unitholders, on the other hand. The directors and officers of our general partner have fiduciary duties to manage us in a manner beneficial to us and our limited partners. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to MGG, the owner of our general partner, and its affiliates. The board of directors of our general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

These conflicts may include, among others, the following:

- our general partner is allowed to take into account the interests of parties other than us, including MGG, and their respective affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our general partner determines whether or not we incur debt and that decision may affect our credit ratings;

- our general partner has limited its liability and reduced its fiduciary duties under the partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such additional contractual arrangements are fair and reasonable to us;
- our general partner controls the enforcement of obligations owned to us by it and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- our general partner determines the allocation of shared overhead expenses to MGG and us; and
- our general partner interprets and enforces contractual obligations between us and our affiliates, on the one hand, and MGG, on the other hand.

Certain executive officers of our general partner own interests in MGG Midstream Holdings, L.P. amounting to approximately 6% of its total ownership. MGG Midstream Holdings, L.P. currently owns the general partner interest and 65% of the limited partner interests in MGG. As a result, these officers could experience additional conflicts between our interests and the interests of MGG.

Affiliates of our general partner may compete with us.

Under our partnership agreement, it is not a breach of our general partner's fiduciary duties for affiliates of our general partner to engage in activities that compete with us. For example, both MGG, which owns our general partner, and MGG's general partner are partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"), which also owns, through affiliates, an interest in the general partner of Buckeye Partners, L.P. ("Buckeye Partners"), and the general partner of SemGroup, L.P. ("SemGroup"), both of which are engaged in the transportation, storage and distribution of refined petroleum products and may acquire other entities that compete with us. Although we do not have extensive operations in the geographic areas primarily served by Buckeye Partners, we will compete directly with Buckeye Partners, SemGroup and perhaps other entities in which CRF has an interest for acquisition opportunities throughout the United States and potentially will compete with Buckeye Partners, SemGroup and these other entities for new business or extensions of the existing services provided by our operating partnerships, creating actual and potential conflicts of interest between us and affiliates of our general partner. In addition, an affiliate of SemGroup is a significant customer of ours.

All of our executive officers face conflicts in the allocation of their time to our business.

Our general partner shares officers and administrative personnel with MGG's general partner to operate both our business and MGG's business. Our general partner's officers, several of whom are also officers of MGG's general partner, will allocate the time they and the other employees of MGG's general partner spend on our behalf and on behalf of MGG. These officers face conflicts regarding the allocation of their and other employees' time, which may adversely affect our results of operations, cash flows and financial condition. These allocations may not necessarily be the result of arms-length negotiations between our general partner and MGG's general partner.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the Internal Revenue Service ("IRS") treats us as a corporation or we become subject to 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 common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, 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 would be substantially reduced. Therefore, our treatment 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 common units.

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. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on us, the cash available for distribution to our unitholders would be reduced. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the target distribution amounts will be adjusted to reflect the impact of that law on us.

The sale or exchange of 50% or more of our capital and profit interests will result in the termination of our partnership for federal income tax purposes.

Our partnership will be considered to have been terminated for federal income tax purposes if, within a 12-month period, there is a sale or exchange of 50% or more of the total interests in our capital and profits. We believe, and will take the position, that a sale of our limited partner units by MGG in April 2005 resulted in our termination and immediate reconstitution as a new partnership for federal income tax purposes. Our termination for tax purposes results in a significant deferral of the depreciation deductions allowable in computing our taxable income for 2005, which will impact unitholders of record at April 2005.

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*

During 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act"), sent Williams an information request based on a preliminary determination that Williams may have systematic problems with petroleum discharges from pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we acquired in April 2002. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the SPCC requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these spills if the EPA were to successfully seek and obtain injunctive relief. We have submitted all information requested to date. We have met with the EPA and the DOJ and anticipate negotiating a final settlement with both agencies in 2006. We have accrued an amount that is less than $22.0 million associated with this matter. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

During the second quarter of 2005, we experienced a product release involving approximately 2,900 barrels of gasoline from our petroleum products pipeline near our Kansas City, Kansas terminal. In regards to this release, we responded on a timely basis to an EPA request for information pursuant to Section 308 of the Act. We can provide no assurances that we will not be assessed civil or other statutory penalties of $100,000 or more by the EPA or other regulatory agencies associated with this release.

We are also a party to various legal actions that have arisen in the ordinary course of our business. We do not believe that the resolution of these matters will have a material adverse effect on our financial condition or results of operations.

ITEM 4. ***Submission of Matters to a Vote of Security Holders***

None.

PART II

ITEM 5. ***Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

We completed our initial public offering in February 2001, and our common units began trading on the New York Stock Exchange under the ticker symbol "WEG". Since our name change to Magellan Midstream Partners, L.P. on September 1, 2003, our common units have been listed on the New York Stock Exchange under the ticker symbol "MMP".

During March 2005, the board of directors of our general partner approved a two-for-one split of our limited partner units. On April 12, 2005, holders of record at the close of business on April 5, 2005 received one additional limited partner unit for each limited partner unit owned on that date. In this report, we have retroactively changed the number of our units and our per unit distribution amount and unit price to give effect to this unit split for all periods presented in this report.

At the close of business on March 1, 2006, we had 210 registered holders and approximately 47,300 beneficial holders of record of our common units. The high and low closing sales price ranges for and distributions paid on our common units by quarter for 2004 and 2005 are as follows:

	2004			2005		
Quarter	**High**	**Low**	**Distribution***	**High**	**Low**	**Distribution***
1st	$27.68	$25.03	$0.42500	$31.50	$29.28	$0.48000
2nd	$27.75	$23.45	$0.43500	$33.01	$30.45	$0.49750
3rd	$27.50	$24.89	$0.44500	$35.30	$31.74	$0.53125
4th	$29.67	$26.51	$0.45625	$34.65	$31.75	$0.55250

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

In addition to common units, we also issued 11,359,388 subordinated units as part of our initial public offering. Because we have exceeded certain cash distribution requirements identified in our partnership agreement, these subordinated units have converted to an equal number of common units over the past three years, with the remaining 5,679,696 subordinated units converting to common units on January 31, 2006. Therefore, we no longer have subordinated units.

Through ownership of our incentive distribution rights, our general partner is entitled to receive increasing percentages of incremental cash we distribute in excess of specified target distribution levels shown below:

	Percentage of Distributions		
		General Partner	
Quarterly Distribution Amount per Unit	**Limited Partners**	**General Partner Interest**	**Incentive Distribution Rights**
Up to $0.289	98%	2%	0%
Above $0.289 up to $0.328	85%	2%	13%
Above $0.328 up to $0.394	75%	2%	23%
Above $0.394	50%	2%	48%

We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as available cash, which is defined in our partnership agreement. The amount of available cash may be greater than or less than the minimum quarterly distribution. We currently pay quarterly cash distributions of $0.5525 per limited partner unit, which entitles our general partner to receive approximately 26% of the total cash distributions paid. In general, we intend to continue increasing our cash distributions in the future assuming no adverse change in our operations, economic conditions and other factors. However, we cannot guarantee that future distributions will continue at such levels.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in "Item 12. Security Ownership of Certain Beneficial Owners and Management" contained herein.

ITEM 6.

SELECTED FINANCIAL AND OPERATING DATA

We have derived the summary selected historical financial data from our current and historical audited consolidated financial statements and related notes. Due to the April 2002 acquisition of Magellan Pipeline, we have restated our consolidated financial statements and notes to reflect the results of operations, financial position and cash flows of Magellan Midstream Partners, L.P. and Magellan Pipeline on a combined basis throughout the periods presented. This financial information is an integral part of, and should be read in conjunction with, the consolidated financial statements and notes thereto. All other amounts have been prepared from our financial records. Information concerning significant trends in the financial condition and results of operations is contained in *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

During October 2004, we acquired certain pipeline and terminal assets (see Note 6—Acquisitions in the accompanying consolidated financial statements), which had a significant impact on our operating results, financial position and cash flows following this acquisition.

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 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 our environmental liabilities and indemnifications can be found in Item 1. *Business—Environmental*, Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Note 18—Commitments and Contingencies in the accompanying consolidated financial statements.

In March 2005, the board of directors of our general partner approved a two-for-one split of our limited partner units. According to the provisions of Financial Accounting Standards Board ("FASB") Statement No. 128, *Earnings Per Share*, we have retroactively changed the number of our limited partner units and the net income and distribution per limited partner unit amounts to give effect to this two-for-one split for all periods presented in this report.

We define EBITDA, which is not a generally accepted accounting principles ("GAAP") measure, in the following schedules as net income plus provision for income taxes, debt prepayment premiums, write-off of unamortized debt placement fees, debt placement fee amortization, interest expense (net of interest income) and depreciation and amortization. EBITDA should not be considered an alternative to net income, operating profit, cash flow from operations or any other measure of financial performance presented in accordance with GAAP. Because EBITDA excludes some items that affect net income and these items may vary among other companies, the EBITDA data presented may not be comparable to similarly titled measures of other companies. Our management uses EBITDA as a performance measure to assess the viability of projects and to determine overall rates of return on alternative investment opportunities. A reconciliation of EBITDA to net income, the nearest comparable GAAP measure, is included in the following schedules.

In addition to EBITDA, the non-GAAP measure of operating margin (in the aggregate and by segment) is presented in the following table. We compute the components of operating margin by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables (see Note 17—Segment Disclosures in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit). We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and G&A expenses, which management does not consider when evaluating the core profitability of an operation.

	Year Ended December 31,				
	2001	2002	2003	2004	2005
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 339,412	$ 363,740	$ 372,848	$ 419,117	$ 500,196
Product sales revenues	108,169	70,527	112,312	275,769	636,209
Affiliate construction and management fee revenues	1,018	210	—	488	667
Total revenues	448,599	434,477	485,160	695,374	1,137,072
Operating expenses including environmental expenses net of indemnifications	160,880	155,146	166,883	179,657	229,795
Product purchases	95,268	63,982	99,907	255,599	582,631
Equity earnings	—	—	—	(1,602)	(3,104)
Operating margin	192,451	215,349	218,370	261,720	327,750
Depreciation and amortization expense	35,767	35,096	36,081	41,845	56,307
Affiliate G&A expense	47,365	43,182	56,846	54,466	61,131
Operating profit	109,319	137,071	125,443	165,409	210,312
Interest expense, net	12,113	21,758	34,536	35,435	48,258
Debt prepayment premium	—	—	—	12,666	—
Write-off of unamortized debt placement costs	—	—	—	5,002	—
Debt placement fee amortization	253	9,950	2,830	3,056	2,871
Other (income) expense, net	(431)	(2,112)	(92)	(953)	(300)
Income before income taxes	97,384	107,475	88,169	110,203	159,483
Provision for income taxes[a]	29,512	8,322	—	—	—
Net income	$ 67,872	$ 99,153	$ 88,169	$ 110,203	$ 159,483
Basic net income per limited partner unit	$ 0.93	$ 1.84	$ 1.66	$ 1.72	$ 2.04
Diluted net income per limited partner unit	$ 0.93	$ 1.84	$ 1.66	$ 1.72	$ 2.03
Balance Sheet Data:					
Working capital (deficit)	$ (2,211)	$ 47,328	$ 77,438	$ 71,737	$ (206)
Total assets	1,104,559	1,120,359	1,194,624	1,817,832	1,876,518
Long-term debt	139,500	570,000	569,100	789,568	782,639
Affiliate long-term note payable[b]	138,172	—	—	—	—
Partners' capital	589,682	451,757	498,149	789,109	807,990
Cash Distribution Data:					
Cash distributions declared per unit[c]	$ 1.01	$ 1.36	$ 1.59	$ 1.76	$ 2.06
Cash distributions paid per unit[c]	$ 0.72	$ 1.29	$ 1.53	$ 1.72	$ 1.97

	Year Ended December 31,				
	2001	2002	2003	2004	2005
	(in thousands, except per unit amounts and operating statistics)				
Other Data:					
Operating margin:					
Petroleum products pipeline system	$143,711	$163,233	$162,494	$192,841	$247,245
Petroleum products terminals	38,240	43,844	46,909	58,522	69,414
Ammonia pipeline system	10,500	8,272	8,094	7,328	7,685
Allocated partnership depreciation costs[d]	—	—	873	3,029	3,406
Operating margin	$192,451	$215,349	$218,370	$261,720	$327,750
EBITDA:					
Net income	$ 67,872	$ 99,153	$ 88,169	$110,203	$159,483
Provision for income taxes[a]	29,512	8,322	—	—	—
Debt prepayment premium	—	—	—	12,666	—
Write-off of unamortized debt placement costs	—	—	—	5,002	—
Debt placement fee amortization	253	9,950	2,830	3,056	2,871
Interest expense, net	12,113	21,758	34,536	35,435	48,258
Depreciation and amortization	35,767	35,096	36,081	41,845	56,307
EBITDA	$145,517	$174,279	$161,616	$208,207	$266,919
Petroleum products pipeline system:					
Transportation revenue per barrel shipped	$ 0.908	$ 0.949	$ 0.964	$ 0.997	$ 1.026
Transportation barrels shipped (millions)	236.1	234.6	237.6	255.0	297.7
Petroleum products terminals:					
Marine terminal average storage capacity utilized per month (million barrels)[e]	15.7	16.2	15.2	16.4	18.6
Marine terminal throughput (million barrels)[f]	11.5	20.5	22.2	28.9	48.4
Inland terminal throughput (million barrels)	56.7	57.3	61.2	101.2	111.1
Ammonia pipeline system:					
Volume shipped (thousand tons)	763	712	614	765	713

(a) Prior to our initial public offering on February 9, 2001, our petroleum products terminals and ammonia pipeline system operations were subject to income taxes. Prior to our acquisition of Magellan Pipeline on April 11, 2002, Magellan Pipeline was also subject to income taxes. Because we are a partnership, the petroleum products terminals and ammonia pipeline system were no longer subject to income taxes after our initial public offering, and Magellan Pipeline was no longer subject to income taxes following our acquisition of it.

(b) At the time of our initial public offering, the affiliate note payable associated with the petroleum products terminals operations was contributed to us as a capital contribution by a former affiliate.

(c) Cash distributions declared represent distributions declared associated with each respective calendar year. Distributions were declared and paid within 45 days following the close of each quarter. Cash distributions declared for 2001 include a pro-rated distribution for the first quarter, which included the period from February 10, 2001 through March 31, 2001. Cash distributions paid represent cash payments for distributions for each of the periods presented.

(d) During 2003, certain assets were contributed to us and were recorded as property, plant and equipment at the partnership level and not at the segment level. Prior to 2003 all property, plant and equipment was recorded at the segment level. The associated depreciation expense was allocated to our various business segments, which in turn, recognized these allocated costs as operating expense. Consequently, segment operating margins were reduced by these costs.

(e) For the year ended December 31, 2004, represents the average monthly storage capacity utilized for the three months we owned the East Houston, Texas facility (0.6 million barrels) and the weighted average storage capacity utilized for the full year at our other marine terminals (15.8 million barrels). For the year ended December 31, 2005, represents the average storage capacity utilized for the four months that we owned our Wilmington, Delaware terminal (1.8 million barrels) and the average monthly storage capacity utilized for the full year at our other marine terminals (16.8 million barrels).

(f) The increase in our marine terminal throughput from 2004 to 2005 was primarily due to a full year of activity at our East Houston facility, which was acquired in October 2004.

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 refined petroleum products. Our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 45 terminals;
- petroleum products terminals, which principally includes our seven marine terminal facilities and 29 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our company. 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, 2005.

Significant Events

Two-for-one split. During March 2005, the board of directors of our general partner approved a two-for-one split of our limited partner units. On April 12, 2005, holders of record at the close of business on April 5, 2005 received one additional limited partner unit for each limited partner unit owned on that date. In this report, we have retroactively changed the number of our units and our per unit distribution amounts to give effect to this unit split for all periods presented.

Recent Developments

On January 18, 2006, the board of directors of our general partner declared a quarterly cash distribution of $0.5525 per unit for the period of October 1 through December 31, 2005. Including this declaration, we paid distributions equal to $2.06 per unit related to 2005 compared to $1.76 per unit related to 2004, an increase in excess of 17%. In addition, the $0.5525 per unit distribution represented a 110% increase compared to our $0.2625 per unit distribution at the time of our initial public offering in February 2001. The $0.5525 per unit distribution was paid on February 14, 2006 to unitholders of record on January 30, 2006.

During February 2006, Magellan Midstream Holdings, L.P. ("MGG"), the owner of our general partner interest, sold 35% of its MGG common units in an initial public offering. We did not receive any of the proceeds from MGG's initial public offering and do not expect our ownership structure or operations to be materially impacted by this transaction. In connection with the closing of this offering, we amended our partnership agreement to remove the requirement for our general partner to maintain its 2% interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

Overview

Our petroleum products pipeline system and petroleum products terminals generate substantially all of our cash flows. The revenues generated from these petroleum products businesses are significantly influenced by demand for refined petroleum products, which has been growing in the markets we serve. 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 have historically included costs from projects relating both to current and past events. For further discussion of indemnified environmental matters, see "Business—Environmental" under Item 1 of this Annual Report on Form 10-K.

A prolonged period of high refined product prices could lead to a reduction in demand and result in lower shipments on our pipeline system and reduced demand for our terminal services. In addition, fluctuations in the prices of refined petroleum products impact the amount of cash our petroleum products pipeline system generates from its third-party supply agreement and its petroleum products blending and fractionation operations. Also, 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 which could impact our results of operations, financial position and cash flows).

Petroleum Products Pipeline System. Our petroleum products pipeline system is comprised of a common carrier pipeline that provides transportation, storage and distribution services for petroleum products and liquefied petroleum gases 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 products pipeline system can access more than 40% of the refinery capacity in the continental United States. The pipeline generates approximately 80% of its revenues, excluding the sale of petroleum products, through transportation tariffs for volumes of petroleum products it ships. 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 on a long-term basis and by providing data services and product services such as ethanol unloading and loading, additive injection, custom blending and laboratory testing.

In general, we do not take title to the products that we transport. However, we do take title to products related to our petroleum products blending and fractionation operations and third-party supply agreement, both of which are included in our petroleum products pipeline system segment. We assumed the third-party supply agreement in October 2004 as part of a pipeline system acquisition, and this agreement requires us to buy and sell significant quantities of petroleum products, to which we routinely take title.

Although our petroleum products blending and fractionation operations and third-party supply agreement generate significant revenues, 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 Products Terminals. Our petroleum products terminals segment is comprised of marine and inland terminals, which store and distribute gasoline and other petroleum products throughout 12 states. Our marine terminals are large storage and distribution terminals that are strategically located near major refining hubs along the U.S. Gulf and East Coasts and principally serve refiners and large end-users of petroleum products. We earn revenues at our marine facilities primarily from storage fees we charge and from 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.

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. Effective February 2003, we entered into an agreement with a third-party pipeline company to operate our ammonia pipeline system. Operating costs and expenses charged to us are principally fixed costs related to maintenance and field personnel. Other costs, including power, fluctuate with volumes transported on the pipeline.

Acquisition History

We have significantly increased our operations over the past three years, including the following acquisitions:

- in November and December 2005, the acquisition of two terminals on our petroleum products pipeline system, located in Wichita, Kansas and Aledo, Texas;
- in September 2005, the acquisition of a marine terminal near Wilmington, Delaware;
- in October 2004, the acquisition of a 2,000-mile petroleum products pipeline system;
- in March 2004, the acquisition of a 50% ownership interest in a crude oil pipeline company;
- in January 2004, the acquisition of six inland terminals and the remaining 21% ownership interest in eight terminals; and
- in July 2003, the acquisition of a petroleum products blending operation.

Results of Operations

We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure used by our management to evaluate the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Operating profit includes expense items, such as depreciation and amortization and general and administrative ("G&A") expenses, which management does not consider when evaluating the core profitability of an operation.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2005

	Year Ended December 31, 2004	Year Ended December 31, 2005
Financial Highlights (in millions)		
Revenues:		
Transportation and terminals revenues:		
Petroleum products pipeline system	$315.0	$ 381.9
Petroleum products terminals	91.3	105.6
Ammonia pipeline system	13.9	15.8
Intersegment eliminations	(1.1)	(3.1)
Total transportation and terminals revenues	419.1	500.2
Product sales	275.8	636.2
Affiliate management fees	0.5	0.7
Total revenues	695.4	1,137.1
Operating expenses, environmental expenses and environmental reimbursements:		
Petroleum products pipeline system	140.2	185.4
Petroleum products terminals	37.1	42.3
Ammonia pipeline system	6.6	8.2
Intersegment eliminations	(4.2)	(6.1)
Total operating expenses, environmental expenses and environmental reimbursements	179.7	229.8
Product purchases	255.6	582.7
Equity earnings	(1.6)	(3.1)
Operating margin	261.7	327.7
Depreciation and amortization	41.8	56.3
Affiliate G&A expenses	54.5	61.1
Operating profit	$165.4	$ 210.3
Operating Statistics		
Petroleum products pipeline system:		
Transportation revenue per barrel shipped	$0.997	$ 1.026
Transportation barrels shipped (million barrels)	255.0	297.7
Petroleum products terminals:		
Marine terminal facilities:		
Average storage capacity utilized per month (million barrels)[(a)]	16.4	18.6
Throughput (million barrels)[(b)]	28.9	48.4
Inland terminals:		
Throughput (million barrels)	101.2	111.1
Ammonia pipeline system:		
Volume shipped (thousand tons)	765	713

(a) For the year ended December 31, 2005, represents the average storage capacity utilized for the four months we owned our Wilmington, Delaware facility (1.8 million barrels) and the average storage capacity utilized for the full year at our other marine terminals (16.8 million barrels). For the year ended December 31, 2004, represents the average storage capacity utilized for the three months we owned our East Houston, Texas facility (0.6 million barrels) and the average storage capacity utilized for the full year at our other marine terminals (15.8 million barrels).

(b) The increase in our marine terminal throughput from 2004 to 2005 was primarily due to a full year of activity at our East Houston facility, which was acquired in October 2004.

Transportation and terminals revenues for the year ended December 31, 2005 were $500.2 million compared to $419.1 million for the year ended December 31, 2004, an increase of $81.1 million, or 19%. This increase was a result of:

- an increase in petroleum products pipeline system revenues of $66.9 million, or 21%, primarily attributable to revenues from our October 2004 pipeline system acquisition. In addition, our existing pipeline system experienced higher revenues because of increased diesel fuel shipments. Further, we earned more ancillary revenues related to services such as additives, ethanol blending, terminal services and management fee income;

- an increase in petroleum products terminals revenues of $14.3 million, or 16%. The 2005 period benefited from our East Houston marine terminal, which was acquired as part of our pipeline system acquisition in October 2004, and our Wilmington marine facility, which we acquired in September 2005. Revenues at our other marine terminals increased as well due to higher storage capacities, utilization and rates. Increased throughput and higher additive injection fees at our inland terminals further benefited the 2005 period; and

- an increase in ammonia pipeline system revenues of $1.9 million, or 14%. Higher tariffs associated with new transportation agreements, which became effective July 1, 2005, more than offset reduced volumes. The lower volumes primarily reflect customers' continued maintenance of tight inventory levels due to increased production costs as a result of higher natural gas prices in 2005.

Operating expenses, environmental expenses and environmental reimbursements combined were $229.8 million for the year ended December 31, 2005 compared to $179.7 million for the year ended December 31, 2004, an increase of $50.1 million, or 28%. By business segment, this increase was principally the result of:

- an increase in petroleum products pipeline system expenses of $45.2 million, or 32%, primarily attributable to operating costs associated with the pipeline system we acquired in October 2004. Increased expenses related to higher environmental accruals associated with historical incidents, power costs and system integrity spending for tank maintenance and pipeline testing also impacted the 2005 period;

- an increase in petroleum products terminals expenses of $5.2 million, or 14%. Expenses increased due to operating costs associated with the acquisitions of our East Houston and Wilmington marine facilities. In addition, 2005 expenses were higher because of environmental accruals associated with historical incidents, asset retirements and property taxes; and

- an increase in ammonia pipeline system expenses of $1.6 million, or 24%, primarily attributable to increased system integrity costs and higher property taxes due to an adjustment that positively impacted the 2004 period.

Revenues from product sales were $636.2 million for the year ended December 31, 2005, while product purchases were $582.7 million, resulting in gross margin from these transactions of $53.5 million. The gross margin resulting from product sales and purchases for the 2005 period increased $33.3 million compared to gross margin for the 2004 period of $20.2 million, resulting from product sales for the year ended December 31, 2004 of $275.8 million and product purchases of $255.6 million. The gross margin increase in 2005 primarily resulted from the impact of very high and increasing gasoline prices on our petroleum products blending and fractionation operations and the third-party supply agreement we assumed as part of the pipeline assets we acquired in October 2004. We expect the annual amount of product sales and purchases to remain at a higher level than historically reported prior to October 2004 as a result of this agreement. However, we expect the gross margin related to this agreement to be substantially lower on an annual basis once refined product prices stabilize.

Equity earnings were $3.1 million during the year ended December 31, 2005 and $1.6 million for the 2004 period. The increase is due primarily to increased shipments on our 50%-owned crude oil pipeline company that we acquired in March 2004 and a full year ownership in 2005 compared to 10 months in 2004.

Operating margin increased $66.0 million, or 25%, primarily due to incremental operating results associated with recent acquisitions, higher gross margin from product sales and improved utilization of our other assets.

Depreciation and amortization expense was $56.3 million for the year ended December 31, 2005 compared to $41.8 million for the year ended December 31, 2004, an increase of $14.5 million, or 35%, primarily related to our October 2004 pipeline system acquisition and terminal acquisitions and capital improvements over the past year.

Affiliate G&A expenses for the year ended December 31, 2005 were $61.1 million compared to $54.5 million for the year ended December 31, 2004, an increase of $6.6 million, or 12%. This increase was primarily attributable to additional G&A personnel and costs resulting from our October 2004 pipeline system acquisition. Higher equity-based incentive compensation expense during the 2005 period was partially offset by transition costs associated with our separation from the former owner of our general partner during the 2004 period. Excluding non-cash incentive compensation expense, our actual cash outlay for G&A costs, as determined by our agreement with the owner of our general partner, was $49.9 million for the year ended 2005 and $42.1 million for 2004. Based on this agreement, the amount of G&A costs we pay increases by 7% annually and by incremental G&A expenses related to completed acquisitions. Based on our current asset portfolio, we expect to pay G&A costs, net of reimbursements, of $53.4 million during 2006.

Interest expense, net of interest income, for the year ended December 31, 2005 was $48.3 million compared to $35.4 million for the year ended December 31, 2004, an increase of $12.9 million, or 36%. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $799.4 million during 2005 from $622.6 million during 2004 primarily due to the financing associated with our October 2004 pipeline system acquisition. Further, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 6.6% for the 2005 period from 6.1% for the 2004 period primarily due to rising interest rates.

While we had no refinancing costs in 2005, net refinancing costs were $16.7 million during 2004. These costs included a $12.7 million debt prepayment premium related to the early extinguishment of a portion of our previously outstanding Magellan Pipeline notes in May 2004 and a $5.0 million write-off for unamortized debt placement fees associated with the retired debt. Partially offsetting these charges was a $1.0 million gain on an interest rate hedge related to the refinancing.

Net income for the year ended December 31, 2005 was $159.5 million compared to $110.2 million for the year ended December 31, 2004, an increase of $49.3 million, or 45%.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2004

	Year Ended December 31,	
	2003	**2004**
Financial Highlights (in millions)		
Revenues:		
Transportation and terminals revenues:		
Petroleum products pipeline system	$281.4	$315.0
Petroleum products terminals	78.9	91.3
Ammonia pipeline system	12.6	13.9
Intersegment eliminations	—	(1.1)
Total transportation and terminals revenues	372.9	419.1
Product sales	112.3	275.8
Affiliate management fees	—	0.5
Total revenues	485.2	695.4
Operating expenses, environmental expenses and environmental reimbursements:		
Petroleum products pipeline system	128.5	140.2
Petroleum products terminals	34.7	37.1
Ammonia pipeline system	4.5	6.6
Intersegment eliminations	(0.8)	(4.2)
Total operating expenses, environmental expenses and environmental reimbursements	166.9	179.7
Product purchases	99.9	255.6
Equity earnings	—	(1.6)
Operating margin	218.4	261.7
Depreciation and amortization	36.1	41.8
Affiliate G&A expenses	56.9	54.5
Operating profit	$125.4	$165.4
Operating Statistics		
Petroleum products pipeline system:		
Transportation revenue per barrel shipped	$0.964	$0.997
Transportation barrels shipped (million barrels)	237.6	255.0
Petroleum products terminals:		
Marine terminal facilities:		
Average storage capacity utilized per month (million barrels)[(a)]	15.2	16.4
Throughput (million barrels)	22.2	28.9
Inland terminals:		
Throughput (million barrels)	61.2	101.2
Ammonia pipeline system:		
Volume shipped (thousand tons)	614	765

(a) For the year ended December 31, 2004, represents the average storage capacity utilized for the three months we owned our East Houston, Texas facility (0.6 million barrels) and the average storage capacity utilized for the full year at our other marine terminals (15.8 million barrels).

Transportation and terminals revenues for the year ended December 31, 2004 were $419.1 million compared to $372.9 million for the year ended December 31, 2003, an increase of $46.2 million, or 12%. This increase was a result of:

- an increase in petroleum products pipeline system revenues of $33.6 million, or 12%, primarily attributable to additional revenues from our October 2004 pipeline system acquisition and significantly higher diesel and aviation fuel volumes on our existing pipeline system during 2004 resulting from increased market demand due to the improving U.S. economy. Further, management fee income associated with our operation of the Longhorn pipeline beginning in 2004 and higher additive and tank lease revenues also contributed to the revenue increase;

- an increase in petroleum products terminals revenues of $12.4 million, or 16%, primarily due to additional revenues from our acquisition of ownership interests in 14 inland terminals during January 2004 and our marine terminal in East Houston, Texas, which was acquired as part of the pipeline system acquisition in October 2004. Further, higher utilization and rates at our marine terminals and increased throughput at our other inland terminals benefited the 2004 period; and
- an increase in ammonia pipeline system revenues of $1.3 million, or 10%, primarily due to significantly increased transportation volumes during 2004. Volumes increased primarily due to the implementation of a new incentive tariff program during late 2003 and higher farm commodity prices which increased demand for ammonia fertilizer.

Operating expenses, environmental expenses and environmental reimbursements combined were $179.7 million for the year ended December 31, 2004 compared to $166.9 million for the year ended December 31, 2003, an increase of $12.8 million, or 8%. By business segment, this increase was principally the result of:

- an increase in petroleum products pipeline system expenses of $11.7 million, or 9%, primarily attributable to operating costs associated with the pipeline system acquired in October 2004, unfavorable product loss allowances, asset retirements, higher allocated depreciation that is charged as an operating expense since third-quarter 2003, increased asset integrity costs and higher insurance expenses. These increases were partially offset by lower employee costs due to a benefits accrual recorded during 2003 associated with the June 2003 change in control of our general partner;
- an increase in petroleum products terminals expenses of $2.4 million, or 7%, primarily due to operating costs associated with acquisition of the ownership interests in 14 inland terminals and the East Houston marine terminal. These increases were partially offset by reduced asset retirements and lower employee costs due to a benefits accrual recorded during 2003 associated with the change in control of our general partner;
- an increase in ammonia pipeline system expenses of $2.1 million, or 47%, primarily attributable to higher system integrity costs and environmental accruals, partially offset by lower property taxes due to a favorable adjustment during the 2004 period; and
- an increase in intersegment eliminations of $3.4 million primarily due to higher allocations of corporate depreciation to the business segments as an operating expense. We did not have depreciable assets recorded at the partnership level until third-quarter 2003.

Revenues from product sales were $275.8 million for the year ended December 31, 2004, while product purchases were $255.6 million, resulting in gross margin from these transactions of $20.2 million. The gross margin resulting from product sales and purchases for the 2004 period increased $7.8 million compared to gross margin for the 2003 period of $12.4 million, resulting from product sales for the year ended December 31, 2003 of $112.3 million and product purchases of $99.9 million. The gross margin increase in 2004 primarily reflects increased product sales from our acquisition of the petroleum products blending operation in July 2003. The amount of product sales and product purchases increased substantially during 2004 primarily as a result of the third-party supply agreement we assumed as part of our October 2004 pipeline system acquisition.

While we had no equity earnings in 2003, equity earnings were $1.6 million during the year ended December 31, 2004 as a result of our acquisition of a 50% interest in a crude oil pipeline company in March 2004.

Operating margin increased by $43.3 million, or 20%, primarily due to incremental operating results associated with 2004 acquisitions and improved utilization of our other assets. Operating margin also improved due to lower transition expenses during 2004 associated with the change in control of our general partner in June 2003.

Depreciation and amortization expense was $41.8 million for the year ended December 31, 2004 compared to $36.1 million for the year ended December 31, 2003, an increase of $5.7 million, or 16%, primarily related to the additional depreciation expense associated with assets acquired during 2004.

Affiliate G&A expenses for the year ended December 31, 2004 were $54.5 million compared to $56.9 million for the year ended December 31, 2003, a decline of $2.4 million, or 4%. This decrease was primarily attributable to the following items:

- $2.1 million lower incentive compensation expense during 2004, primarily because of the early vesting of restricted units in 2003 under our equity-based compensation plan as a result of the change in control of our general partner; and
- $5.0 million lower transition costs associated with the separation of our G&A functions from the former owner of our general partner. During 2003, the transition costs were $5.8 million, which principally related to a benefits accrual and creation of our stand-alone information technology functions. Comparatively, the 2004 period included $0.8 million of transition costs.

Partially offsetting these decreases was an increase in the amount of affiliate G&A expense we record. Excluding non-cash incentive compensation expense, our actual cash outlay for G&A costs is determined by an agreement with the owner of our general partner. The owner of our general partner reimburses us for any G&A expenses in excess of this amount up to a certain limit. We record total G&A costs, including the amount that is reimbursed by the owner of our general partner, as an expense, and we record the excess amount for which we are reimbursed as a capital contribution by our general partner. Prior to the change in control of our general partner during June 2003, we were unable to identify specific costs required to support our operations. As a result, we recorded only our actual cash G&A costs and non-cash expenses for our equity-based incentive plan as expense in our financial results. Due to the change in our organizational structure following the change in control of our general partner in June 2003, we could clearly identify all of our G&A expenses. For 2004 and 2003, our actual cash outlay for G&A costs was $42.1 million and $38.2 million, respectively, based on the agreement with our general partner.

Interest expense, net of interest income, for the year ended December 31, 2003 was $34.5 million compared to $35.4 million for the year ended December 31, 2004, an increase of $0.9 million, or 3%. The weighted-average interest rate on our borrowings decreased slightly from 6.3% for the 2003 period to 6.1% in the 2004 period due in part to our May 2004 debt refinancing. Our average debt outstanding increased from $570.0 million during 2003 to $622.6 million during 2004 primarily due to the financing associated with our October 2004 pipeline system acquisition.

Net refinancing costs associated with our May 2004 debt placement were $16.7 million. These costs included a $12.7 million debt prepayment premium related to the early extinguishment of a portion of our previously outstanding Magellan Pipeline notes and a $5.0 million non-cash write-off for unamortized debt placement fees associated with the retired debt. Partially offsetting these charges was a $1.0 million gain on an interest rate hedge related to the refinancing.

Net income for the year ended December 31, 2004 was $110.2 million compared to $88.2 million for the year ended December 31, 2003, an increase of $22.0 million, or 25%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

During 2005, net cash provided by operating activities exceeded distributions paid and net maintenance capital requirements by $38.2 million.

Net cash provided by operating activities was $224.8 million for the year ended December 31, 2005, $236.5 million for 2004 and $144.0 million for 2003.

- The $11.7 million decrease from 2004 to 2005 was primarily attributable to:
  - an increase in accounts receivable and inventory of $13.3 million and $34.8 million, respectively, primarily resulting from the third-party supply agreement we assumed in connection with our October 2004 pipeline system acquisition;
  - a decrease in accrued product shortages of $7.5 million in 2005 compared to an increase in 2004 of $7.5 million; and
  - a decrease in cash collateral associated with our third-party supply agreement of $1.5 million in 2005 compared to an increase in cash collateral in 2004 of $14.0 million.

  These decreases were partially offset by:
  - increased net income of $49.3 million largely resulting from our October 2004 pipeline system acquisition, acquisitions over the past year, higher gross margin from product sales and improved utilization of our other assets; and
  - an increase in accrued product purchases of $17.5 million primarily due to the increase in inventory described above.
- The $92.5 million increase from 2003 to 2004 was primarily attributable to:
  - increased net income of $22.0 million including results from our operations associated with the pipeline system we acquired in October 2004;
  - a $12.7 million prepayment premium during 2004 on a portion of our Magellan Pipeline notes, which reduced net income but was classified as cash from financing activities;
  - collection of $35.0 million during 2004 related to our indemnification settlement agreement;
  - an increase in our equity-based incentive compensation liability in 2004 versus 2003 of $9.3 million primarily due to the settlement of awards during 2003 related to the change in control of our general partner; and
  - $10.1 million lower cash payments in 2004 as compared to payments made during 2003 associated with our separation from the former owner of our general partner.

Net cash used by investing activities for the years ended December 31, 2005, 2004 and 2003 was $75.7 million, $712.3 million and $45.9 million, respectively. During 2005, we acquired a marine terminal in Wilmington, Delaware for $55.3 million and petroleum products pipeline system terminals in Wichita, Kansas and Aledo, Texas for $10.9 million on a combined basis. In addition, we spent $7.6 million to buy out of obligations related to a portion of our third-party supply agreement and $92.8 million for capital expenditures, excluding acquisitions. These cash expenditures were partially offset by our sales of marketable securities which, net of purchases, generated $87.8 million of cash. During 2004, our net investments in marketable securities used $87.8 million of cash. In addition, we acquired the following assets during 2004: (i) ownership in 14 petroleum products terminals located in the southeastern United States for $25.4 million; (ii) a 50% ownership in a crude oil pipeline company for $25.0 million; and (iii) petroleum products pipeline system assets for $488.9 million plus $3.3 million of incurred transaction costs and $30.1 million for inventory. During 2003, we acquired our petroleum products blending operation and related inventory for $15.3 million. Total maintenance capital expenditures before indemnifications and reimbursements were $31.4 million, $21.9 million and $20.9 million in 2005, 2004 and 2003, respectively.

Net cash provided (used) by financing activities for the years ended December 31, 2005, 2004 and 2003 was $(142.5) million, $394.3 million and $(61.8) million, respectively. Cash was used during 2005 primarily to pay cash distributions to our unitholders. Cash provided during 2004 principally included the debt and equity financings that were completed in conjunction with our pipeline system acquisition in October 2004, partially offset by the repayment of debt in connection with our May 2004 refinancing and cash distributions paid. Cash was used during 2003 primarily to pay cash distributions to our unitholders.

During 2005, we paid $160.5 million in cash distributions to our unitholders. The quarterly distribution amount associated with the fourth quarter of 2005 was $0.5525 per unit. If we continue to pay cash distributions at this current level and the number of outstanding units remains the same, total cash distributions of $198.0 million will be paid to our unitholders in 2006, of which $51.4 million, or 26%, would be related to our general partner's 2% ownership interest and incentive distribution rights.

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, referred 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 2005, our maintenance capital spending was $26.1 million, excluding the following:

- $4.3 million for environmental projects that would have been covered by indemnifications settled in May 2004 by our indemnification settlement agreement. We have received $62.5 million through December 31, 2005 pursuant to this agreement; and
- $1.0 million for security enhancements at our marine terminal facilities for which we were reimbursed by the U.S. government.

For 2006, we expect to incur maintenance capital expenditures for our existing businesses of approximately $27.0 million, excluding $7.0 million of maintenance capital that would have been covered by the indemnification discussed above.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During 2005, we spent cash of approximately $61.4 million for organic growth opportunities and $66.1 million for acquisitions. Based on projects currently underway or in advanced stages of development, we plan to spend at least $145.0 million on organic growth capital spending in 2006, exclusive of amounts associated with future acquisitions.

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 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.

As of December 31, 2005, total debt reported on our consolidated balance sheet was $797.0 million, as described below. The difference between this amount and the $799.9 million face value of our outstanding debt is due to adjustments associated with the fair value hedges we have in place for a portion of our outstanding senior notes and unamortized discounts on debt issuances.

In May 2004, we completed a refinancing plan that improved our financial flexibility by providing for the release of the collateral previously securing our debt. This refinancing plan further served to reduce the weighted-average interest rate we incur and lowered our outstanding debt. In October 2004, we borrowed $300.0 million under a short-term acquisition facility and $50.0 million under our revolving credit facility to partially finance the pipeline system we acquired. We repaid these borrowings in October 2004 using proceeds from public debt and equity offerings. Our short-term acquisition facility was cancelled at that time.

5.65% Senior Notes due 2016. On October 15, 2004, we sold $250.0 million of 5.65% senior notes due 2016 in an underwritten public offering as part of the long-term financing of the pipeline system assets we acquired in October 2004. The notes were issued at 99.9% of par, and we received proceeds after underwriters' fees and expenses of approximately $247.6 million. Including the impact of pre-issuance hedges associated with these notes and the swap of $100.0 million of the notes from fixed-rate to floating-rate, the weighted-average interest rate on the notes at December 31, 2005 was 5.6%.

6.45% Senior Notes due 2014. On May 25, 2004, we sold $250.0 million of 6.45% senior notes due 2014 in an underwritten public offering at 99.8% of par. We received proceeds after underwriters' fees and expenses of approximately $246.9 million. Including the impact of pre-issuance hedges associated with these notes, the effective interest rate on these notes at December 31, 2005 was 6.3%.

The indentures under which both the 5.65% and 6.45% notes were issued do not limit our ability to incur additional unsecured debt. The indentures contain covenants limiting, among other things, our ability to incur indebtedness secured by certain liens, engage in certain sale-leaseback transactions, and consolidate, merge or dispose of all or substantially all of our assets. We are in compliance with these covenants.

Magellan Pipeline Notes. In connection with the long-term financing of our acquisition of Magellan Pipeline, we and Magellan Pipeline entered into a note purchase agreement on October 1, 2002. The $480.0 million borrowed under this agreement included Series A and Series B senior notes. The Series A senior notes included $178.0 million of borrowings that incurred interest based on the six-month Eurodollar rate plus 4.3%. The Series B senior notes included $302.0 million of borrowings that incur interest at a weighted-average fixed rate of 7.7%. Our membership interests in and the assets of Magellan Pipeline initially secured this debt. As a result of our May 2004 refinancing, we repaid the $178.0 million outstanding balance of the Series A senior notes and we incurred $12.7 million of associated prepayment premiums. Further, in exchange for a $1.9 million payment, the Series B noteholders released the collateral that secured these notes, except for cash deposited monthly by Magellan Pipeline into a cash escrow account in anticipation of semi-annual interest payments.

The weighted-average interest rate for the Series B senior notes, including the impact of the swap of $250.0 million of the notes from fixed-rate to floating-rate, was approximately 8.1% at December 31, 2005. The maturity date of these notes is October 7, 2007, with scheduled prepayments equal to 5% of the outstanding balance on October 7, 2005 and October 7, 2006. Magellan Pipeline repaid $15.1 million of these notes on October 7, 2005 in connection with the first scheduled prepayment. We guarantee payment of interest and principal by Magellan Pipeline.

The note purchase agreement under which these notes were issued, as amended during our May 2004 refinancing, requires Magellan Pipeline to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 3.50 to 1.00, and (ii) consolidated EBITDA to interest expense of at least 3.25 to 1.00. It also requires us to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 4.50 to 1.00, and (ii) consolidated EBITDA to interest expense of at least 2.50 to 1.00. In addition, the note purchase agreement contains additional covenants that limit Magellan Pipeline's ability to, among other things, incur additional indebtedness, encumber its assets, make debt or equity investments, make loans or advances, engage in certain transactions with affiliates, merge, consolidate, liquidate or dissolve, sell or lease a material portion of its assets, engage in sale and leaseback transactions and change the nature of its business. We are in compliance with these covenants.

Revolving Credit Facility. In connection with our May 2004 refinancing, we entered into a five-year $125.0 million revolving credit facility, which we subsequently increased to $175.0 million in September 2004. Borrowings under this facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.6% to 1.5% based upon our credit ratings. As of December 31, 2005, $13.0 million was outstanding under this facility, and $1.1 million of the facility was obligated for letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets. As of December 31, 2005, the weighted-average interest rate on borrowings outstanding under this facility was 5.1%.

The revolving credit facility requires us to maintain specified ratios of consolidated debt to EBITDA of no greater than 4.5 to 1.0, and consolidated EBITDA to interest expense of at least 2.5 to 1.0. In addition, the facility contains other covenants limiting our ability to incur additional indebtedness, encumber our assets, make certain investments, engage in certain transactions with affiliates, engage in sale and leaseback transactions, merge, consolidate, liquidate, dissolve or dispose of all of our assets or change the nature of our business. We are in compliance with these covenants.

Interest Rate Derivatives. We utilize interest rate derivatives to manage interest rate risk. In conjunction with our existing debt instruments, we were engaged in the following derivative transactions as of December 31, 2005:

- In October 2004, we entered into a $100.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of our 5.65% senior notes due 2016. This agreement effectively changes the interest rate on $100.0 million of those notes to a floating rate of six-month LIBOR plus 0.6%, with LIBOR set in arrears. This swap agreement expires on October 15, 2016, the maturity date of the 5.65% senior notes; and
- In May 2004, we entered into $250.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline Series B senior notes. These agreements effectively change the interest rate on $250.0 million of the Series B senior notes from a fixed rate of 7.7% to a floating rate of six-month LIBOR plus 3.4%, with LIBOR set in arrears. These swap agreements expire on October 7, 2007, the maturity date of the Magellan Pipeline Series B senior notes.

*Debt-to-Total Capitalization***.** The ratio of debt-to-total capitalization is a measure frequently used by the financial community to assess the reasonableness of a company's debt levels compared to its total capitalization, which is calculated by adding total debt and total partners' capital. Based on the figures shown in our balance sheet, debt-to-total capitalization was 50% at December 31, 2005. Because accounting rules required the acquisition of a portion of Magellan Pipeline to be recorded at historical book values due to the then affiliate nature of the transaction, the $474.5 million difference between the purchase price and book value at the time of the acquisition was recorded as a decrease to our general partner's capital account, thus lowering our overall partners' capital by that amount.

Credit Ratings. Our current corporate credit ratings are BBB by Standard and Poor's and Baa3 by Moody's Investor Services.

Off-Balance Sheet Arrangements

None

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2005 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term and current debt obligations(1)	$ 799.9	$ 14.3	$272.6	$13.0	$500.0
Interest obligations	327.6	52.7	77.9	60.8	136.2
Operating lease obligations	21.0	2.8	4.8	2.9	10.5
Pension and post-retirement medical obligations	22.4	1.7	2.2	1.4	17.1
Purchase commitments:					
Affiliate operating and G&A(2)					
Petroleum product purchases(3)	68.3	67.8	0.5	—	—
Derivative financial instruments(4)					
Equity-based incentive awards(5)	15.9	6.1	9.8	—	—
Environmental remediation(6)	11.0	2.4	1.9	1.9	4.8
Capital project purchase obligations	29.6	29.6	—	—	—
Other purchase obligations	2.8	2.1	0.4	0.1	0.2
Other	12.5	—	—	—	12.5
Total	$1,311.0	$179.5	$370.1	$80.1	$681.3

(1) Excludes market value adjustments to long-term debt associated with qualifying hedges. For purposes of this table, we have assumed that the borrowings under our revolving credit facility as of December 31, 2005 ($13.0 million) will not be repaid until the maturity date of the facility.

(2) We have an agreement with affiliates of our general partner to provide our direct operating and G&A services. This agreement has provisions for termination upon 90-day notice by either party. As a result of the termination provisions of this agreement and the requirement to pay only actual costs as they are incurred, we are unable to determine the actual amount of these commitments. The amount we paid for operating and G&A costs during 2005 was $124.7 million.

(3) We have an agreement to supply a customer with approximately 450,000 barrels of petroleum products per month until the agreement expires in 2018. Related to this supply agreement, we have entered into certain forward contracts to purchase various petroleum products based on future product prices. This amount is an estimated value of our product purchase commitments at December 31, 2005, based on projected product prices.

(4) On December 31, 2005, we had outstanding interest rate swap agreements to hedge against the fair value of $350.0 million of our long-term debt. Because future cash outflows under these agreements, if any, are uncertain, they have been excluded from this table.

(5) Represents amounts we have accrued for equity-based incentive compensation through December 31, 2005 based on when those existing liabilities will be settled. We expect the amounts that will ultimately vest to our employees will exceed these amounts due to anticipated compensation liabilities that will be recognized over the remainder of the vesting periods and changes in our unit prices between December 31, 2005 and the date the unit awards actually vest.

(6) On December 31, 2005, we entered into a 10-year agreement to reach contractual endpoint (as defined in the agreement) for 26 remediation sites. This contract obligates us to pay the remediation costs incurred by the contract counterparty associated with these 26 sites up to a maximum of $14.0 million. The amounts included in the table above represent our accrued environmental liabilities, as of December 31, 2005, associated with these 26 sites. For purposes of this table, we have assumed that these costs will be incurred ratably over the 10-year contract term.

Environmental

Various governmental authorities in the jurisdictions in which we conduct our operations subject us to environmental laws and regulations. We have accrued liabilities for estimated known site restoration costs to be incurred in the future at our facilities and properties, including liabilities for environmental remediation obligations at various sites where we have been identified as a possible responsible party. Under our accounting policies, we record liabilities when site restoration and environmental remediation obligations are either known or considered probable and can be reasonably estimated.

Prior to May 2004, The Williams Companies, Inc. (“Williams”) provided indemnifications to us for assets we previously acquired from it. The indemnifications primarily related to environmental items for periods during which Williams was the owner of those assets. In May 2004, we entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release it from those indemnification obligations. To date, we have received $62.5 million from Williams and expect to receive the remaining balance in installments of $20.0 million and $35.0 million on July 1 of 2006 and 2007, respectively. As of December 31, 2005, known liabilities that would have been covered by these indemnifications were $43.1 million. In addition, we have spent $17.4 million through December 31, 2005 that would have been covered by these indemnifications, including $6.6 million of capital costs.

At the time of MGG's purchase of our general partner interest in June 2003, MGG assumed obligations to indemnify us for $21.9 million of known environmental liabilities. Through December 31, 2005, we have incurred $16.4 million of costs associated with this indemnification obligation, leaving a remaining liability of $5.5 million. Our receivable balance with MGG on December 31, 2005 was $6.7 million.

In July 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to Williams based on a preliminary determination that Williams may have systematic problems with petroleum discharges from pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired in April 2002. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those spills also may have violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these spills if the EPA were to successfully seek and obtain injunctive relief. We have submitted all information requested to date. We have met with the EPA and the DOJ and anticipate negotiating a final settlement with both agencies in 2006. We have accrued an amount that is less than $22.0 million associated with this matter. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

Other Items

Ownership changes. During 2005, MGG sold its remaining limited partner interests in us. MGG continues to own our general partner interest, representing a 2% ownership in us. Due to the trading activity of our limited partner units, we believe that more than 50% of the total interests in our capital and profits had been sold or exchanged over the 12-month period ending April 2005. Because of this, we were terminated for federal income tax purposes and immediately reconstituted as a new partnership, causing a significant reduction in the amount of depreciation deductions allocable to our unitholders in 2005. As a result, we estimate that for only the 2005 tax year our unitholders as of April 2005 were allocated an increased amount of federal taxable income as a percentage of cash distributed to them.

New board member. During May 2005, our general partner's board of directors appointed John P. DesBarres as an independent board member, replacing Mark G. Papa who resigned from this position due to conflicting time commitments.

Variable-rate terminalling agreement. We had a terminalling agreement with a third-party customer under which we provided storage rental and throughput fees based on discounted rates plus a variable fee, which was based on a percentage of the net profits from certain trading activities conducted by our customer. Under this agreement which expired on January 31, 2006, we recognized the storage rental and throughput fees as the services were performed; however, we would not receive revenue from the variable fee if the net trading profits fell below a specified amount or were negative. We earned approximately $6.4 million related to the shared trading profits which was not determinable until the end of the contract term. We elected to defer the recognition of this revenue until the end of the contract term. As a result of settling this agreement, our terminals revenues, operating profit and net income will be favorably impacted by approximately $6.4 million during the first quarter of 2006. While we expect to continue to negotiate similar terminalling arrangements in the future, we cannot predict what future revenues, if any, will be recognized from such arrangements.

Hurricane impact. Hurricanes Katrina and Rita struck the Gulf Coast area of the United States during third-quarter 2005, resulting in damage to the petroleum industry's infrastructure in that region. Many refineries in the Houston, Texas area shut down operations in preparation for the pending storms. Our assets sustained only minor damage from these hurricanes, including two docks at our Marrero, Louisiana marine terminal. Although this terminal remains operational, we are in the process of replacing the damaged docks.

Supply disruptions of petroleum products occurred following the hurricanes because of delays in the return of Gulf Coast refineries to historical operating levels. Although we did experience lower transportation volumes on our petroleum products pipeline system and reduced throughput at our inland terminals during fourth-quarter 2005, our financial results were not materially impacted.

Galena Park marine terminal expansion. During late 2005 and early 2006, we executed a series of long-term terminalling agreements with several customers, which will require us to construct 30 new storage tanks at our Galena Park, Texas marine terminal. Tank construction has begun and we expect the new tanks to be placed into service during 2006 and 2007. We believe these new agreements will significantly contribute to our results of operations and cash flows once construction is complete and the 30 new tanks have been placed into service.

Line break and product release. On January 13, 2006, we experienced a line break and product release of approximately 3,200 barrels from our petroleum products pipeline near Independence, Kansas. We are in the process of estimating the repair and remediation costs associated with the release. We have insurance coverage for this incident with a deductible of $1.5 million. We are unable to estimate with any degree of certainty what penalties, if any, might be assessed by the EPA or other governmental agency, associated with this release, which would not be covered by our insurance policy. Our net cost for repair and remediation plus any penalties that may be assessed could be material to our results of operations or cash flows.

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 and the audit committee 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. We believe the accounting estimate relative to environmental remediation costs to be a "critical accounting estimate" because: (1) estimated expenditures, which will generally be made over the next one to ten years, are subject to cost fluctuations and could change materially, (2) unanticipated third-party liabilities may arise and (3) changes in federal, state and local environmental regulations could significantly increase the amount of the liability. The estimate for environmental liabilities is a critical accounting estimate for all three of our operating segments.

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 liabilities associated with each of our operating units. 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, estimating the costs associated with executing the regulatory phases that can be reasonably estimated and estimating the timing for those expenditures. During the site-specific evaluations, all known information is utilized 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.

Each quarter, 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 and additional findings or changes in federal or state regulations. The estimated environmental liability accruals are adjusted as necessary. Changes in our environmental liabilities since December 31, 2003 are as follows (in millions):

Balance	2004		Balance	2005		Balance
12-31-03	Accruals	Expenditures	12-31-04	Accruals	Expenditures	12-31-05
$26.8	$49.9	$(15.9)	$60.8	$12.7	$(15.3)	$58.2

In May 2004, we entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from its environmental and certain other indemnification obligations to us. From the effective date of our environmental indemnification settlement with Williams, all accrual adjustments associated with amounts that would have been previously indemnified by Williams are no longer reimbursed and therefore reduce our net income.

During 2004, we increased our environmental liability accruals by $49.9 million as a result of: (a) $6.1 million of environmental liabilities assumed through acquisitions completed during the year; (b) an increase of $5.3 million associated with a product release in the Kansas City area; (c) a notification we received during 2004 from the EPA of its intent to assess penalties against us related to certain specified pipeline releases; and (d) the quarterly and annual site assessments by our remediation project managers.

During 2005, we increased our environmental liability accruals by $12.7 million, of which $3.2 million related to pipeline product releases, $0.2 million related to acquisitions and the remainder was primarily attributable to our annual site assessment process.

Our known environmental liabilities at December 31, 2005 are based on estimates that are subject to change, and any changes to these estimates would impact our results of operations and financial position. For example, if our environmental liabilities increased by as much as 15% and assuming that none of this increase was covered by indemnifications or insurance, our expenses would increase by $8.7 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 4% of our operating profit and 5% of our net income for 2005. Assuming our current distribution levels for the entire year, this additional expense would reduce both basic and diluted net income per limited partner unit by approximately $0.10. Such a change would increase our liabilities and decrease equity by approximately 1%. 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 long-term debt agreements as discussed above under "Liquidity and Capital Resources—Liquidity".

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. Straight-line depreciation results in depreciation expense being incurred evenly over the life of the asset. At December 31, 2004 and 2005, the net book value of our property, plant and equipment was $1.5 billion and $1.6 billion, respectively, and we recorded depreciation expense of $40.5 million and $54.9 million during 2004 and 2005, respectively.

The determination of an asset's estimated useful life takes a number of factors into consideration, including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and result in an increase or decrease in depreciation expense. Our terminals, pipelines and related equipment have estimated useful lives of three to 59 years, with a weighted-average asset life of approximately 40 years. If the estimates of our asset lives changed such that the average estimated asset life was 35 years, our depreciation expense for 2005 would increase by $7.6 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 4% of our operating profit and 5% of our net income for 2005. Assuming our current distribution levels for the entire year, this additional expense would reduce both basic and diluted net income per limited partner unit by approximately $0.09. Such a change would decrease total assets by less than 1% and equity by approximately 1%. The impact of such an increase in depreciation costs would likely not have affected our liquidity because, even with the increased costs, we would still comply with the covenants of our long-term debt agreements as discussed above under "Liquidity and Capital Resources—Liquidity".

New Accounting Pronouncements

In November 2005, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") No. FAS 115-1 and FAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments." This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary and the measurement of an impairment loss. This FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities," FASB Statement No. 124, "Accounting for Certain Investments Held by Not-for-Profit Organizations," and Accounting Principles Bulletin ("APB") Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The guidance in this FSP is to be applied to reporting periods beginning after December 15, 2005. We adopted this FSP on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In October 2005, the FASB issued FSP No. 13-1, "Accounting for Rental Costs Incurred During a Construction Period." This FSP requires entities who incur rental costs associated with operating leases to expense such costs as a continuing operating expense. This FSP is required to be implemented beginning January 1, 2006, with early adoption permitted. We adopted the FSP on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In September 2005, the FASB issued Emerging Issue Task Force ("EITF") issue No. 04-13, "Accounting for Purchases and Sales of Inventory With the Same Counterparty." In EITF No. 04-13, the FASB reached a tentative conclusion that inventory purchases and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying APB Opinion No. 29, "Accounting for Nonmonetary Transactions." The tentative conclusions reached by the FASB are required to be applied to transactions completed in reporting periods beginning after March 15, 2006. The adoption of this EITF is not expected to have a material impact on our results of operations, financial position or cash flows.

In May 2005, the FASB published Statement of Financial Accounting Standard ("SFAS") No. 154, "Accounting Changes and Error Corrections." SFAS No. 154 requires retrospective application to prior periods' financial statements of every voluntary change in accounting principle unless it is impracticable to do so. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in nondiscretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change. We adopted this SFAS No. 154 in January 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In March 2005, the FASB issued FIN No. 47, "Accounting for Conditional Asset Retirement Obligations (as amended)." This Interpretation clarified that the term *conditional asset retirement obligation* as used in SFAS No. 143, "Accounting for Asset Retirement Obligations," refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. SFAS No. 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN No. 47 was required to be adopted no later than the end of fiscal years ending after December 15, 2005, with retrospective application for interim financial information permitted. We adopted FIN No. 47 in 2005, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In December 2004, the FASB issued a revision to SFAS No. 123, "Share-Based Payment," referred to as "SFAS No. 123R." Additionally, in October 2005, the FASB issued FSP 123(R)–2, "Practical Accommodation to the Application of Grant Date as Defined in FASB Statement No. 123(R)." This Statement and subsequent revisions establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. This SFAS requires that all equity-based compensation awards to employees be recognized in the income statement based on their fair values, eliminating the alternative to use APB No. 25's intrinsic value method. SFAS No. 123(R) is effective as of the beginning of the first interim period that begins after December 31, 2005. SFAS No. 123(R) applies to all awards granted after the required effective date but is not to be applied to awards granted in periods before the required effective date except to the extent that awards from prior periods are modified, repurchased or cancelled after the required effective date. We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method. Under the modified prospective method, we were required to account for all of our equity-based incentive awards granted prior to January 1, 2006, using the fair value method as defined in SFAS No. 123 instead of our current methodology of using the intrinsic value method as defined in APB No. 25. Due to the structure of our awards, we recognize compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123. Consequently, for the awards granted prior to January 1, 2006, the initial adoption and application of SFAS No. 123(R) did not have a material impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an Amendment of APB No. 29." The guidance in APB No. 29, "Accounting for Nonmonetary Transactions," is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance, however, included certain exceptions to that principle. This SFAS amends APB No. 29

to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS No. 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The initial adoption and application of SFAS No. 153 did not have a material impact on our financial position, results of operations or cash flows.

In May 2004, the FASB issued FSP No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Prescription Drug Act")." FSP No. 106-2 superseded FSP No. 106-1, issued in January 2004. FSP No. 106-2 provides accounting guidance for employers that sponsor post-retirement health care plans which provide prescription drug benefits and receive the subsidy available under the Prescription Drug Act. FSP No. 106-2 also provides disclosure requirements about the effects of the subsidy for companies that offer prescription drug benefits. FAS No. 106-2 was effective on July 1, 2004 and did not have a material impact on our financial position, results of operations or cash flows during 2004.

In March 2004, the FASB issued EITF Statement No. 03-06, "Participating Securities and the Two-Class Method under SFAS No. 128, Earnings Per Share." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by entities that have issued securities other than common units that contractually entitle the holder to participate in distributions and earnings of the company when, and if, it declares distributions on its common units. EITF No. 03-06 also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF No. 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF No. 03-06 did not result in a change in our earnings per unit for any of the periods presented.

Related Party Transactions

In March 2004, we acquired a 50% ownership interest in a crude oil pipeline company. In April 2004, we began operating the related pipeline, for which we received operating fees of $0.5 million and $0.7 million during 2004 and 2005, respectively, which we reported as affiliate management fee revenues. In 2004, we also received $0.3 million for fees to transition accounting, billing and other administrative functions to us. We recorded these fees as other income, which is netted into operating expenses in our results of operations.

On June 17, 2003, Williams sold its ownership interest in us to MGG. Costs and expenses related to activities between Williams and its affiliates and us after June 17, 2003 have been accounted for as unaffiliated third-party transactions. Transactions after June 17, 2003 between us and MGG and its affiliates have been accounted for as affiliate transactions. The following table summarizes expenses from various affiliate companies with us which are reflected as expenses in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2003	2004	2005
Affiliates of Williams—allocated G&A expenses	$23,880	$ —	$ —
Affiliates of Williams—allocated operating expenses	68,079	—	—
Affiliates of Williams—product purchases	472	—	—
MGG—allocated operating expenses	98,804	58,777	65,360
MGG—allocated G&A expenses	32,966	54,466	60,261
MGG GP—allocated operating expenses	—	—	1,551
MGG GP—allocated G&A expenses	—	—	870

In June 2003, we and our general partner entered into a services agreement with MGG pursuant to which MGG agreed to provide the employees necessary to conduct our operations. For the period June 18, 2003 (the date MGG acquired Williams' ownership interest in us) through December 31, 2003, all of the personnel assigned to us remained employees of Williams. On June 18, 2003, MGG entered into a transition services agreement whereby Williams agreed to provide all of our operating and G&A functions through December 31, 2003. MGG allocated all costs it incurred with Williams under this transition services agreement to us and we reimbursed MGG for these costs, subject to our G&A expense reimbursement agreement with MGG. We reimbursed MGG for all payroll and benefit costs it incurred from January 1, 2004 through December 24, 2005. On December 24, 2005, the employees necessary to conduct our operations were transferred to MGG's general partner and the services agreement with MGG was terminated and a new services agreement with MGG's general partner was executed. As a result, we now reimburse MGG's general partner for the costs of employees necessary to conduct our operations. Additionally, in June 2003, MGG agreed to reimburse us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap as defined in the omnibus agreement. The amount of G&A costs that MGG is required to reimburse to us was $6.4 million and $3.3 million in 2004 and 2005, respectively. We settle our affiliate payroll and payroll-related expenses and post-retirement benefit costs with MGG's general partner on a monthly basis. We settle our long-term pension liabilities through annual contributions to MGG's general partner's pension fund.

For the period January 1, 2003 through June 17, 2003, Williams allocated operating expenses to our general partner, which included all operating costs directly associated with our operations. Additionally, Williams allocated to us both direct and indirect G&A expenses, which were subject to an expense limitation.

Williams and certain of its affiliates had indemnified us against certain environmental costs. The environmental indemnifications we had with Williams were settled during 2004. In addition, MGG agreed to assume certain indemnified obligations to us. See Note 18—Commitments and Contingencies for information relative to these items.

Other Related Party Transactions. MGG, which owns our general partner, is partially owned by an affiliate of the Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). Two of the members of our general partner's eight member board of directors are nominees of CRF. On January 25, 2005, CRF, through affiliates, acquired an interest in the general partner of SemGroup, L.P. ("SemGroup") and limited partner interests in SemGroup. CRF's total combined general and limited partner interest in SemGroup is approximately 30%. One of the members of SemGroup's general partner's seven-member board of directors is a nominee of CRF, with three votes on such board. We, through our affiliates, are a party to a number of transactions with SemGroup and its affiliates, details of which are provided in the following table (in millions):

	Year Ended December 31, 2005
Sales of petroleum products	$144.8
Purchases of petroleum products	90.0
Terminalling and other services revenues	5.9
Storage tank lease revenues	2.8
Storage tank lease expense	1.0

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2005, we had recognized a receivable of $6.2 million from and a payable of $6.1 million to SemGroup and its affiliates. The receivable is included with the trade accounts receivable amounts and the payable is included with the accounts payable amounts on our consolidated balance sheets.

CRF also has an ownership interest in the general partner of Buckeye Partners, L.P. ("Buckeye"). In 2005, we incurred $0.3 million of operating expenses with Norco Pipe Line Company, LLC, which is a subsidiary of Buckeye Partners, L.P.

The board of directors of our general partner has adopted a Board of Directors Conflict of Interest Policy and Procedures. In compliance with this policy, CRF has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to SemGroup and Buckeye. As part of these procedures, none of the nominees of CRF will serve on our general partner's board of directors and on SemGroup's or Buckeye's general partner's board of directors at the same time.

During May 2005, our general partner's board of directors appointed John P. DesBarres as an independent board member. Mr. DesBarres currently serves as a board member for American Electric Power Company, Inc. As of December 31, 2005, our operating expenses totaled $1.7 million of principally power costs that we incurred with Public Service Company of Oklahoma, which is a subsidiary of American Electric Power Company, Inc.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives increasing percentages of our total distributions. Distributions to our general partner above the highest target level are at 50%. As the owner of our general partner, MGG indirectly benefits from these distributions. Through ownership of the Class B common units of MGG Midstream Holdings, L.P., which, at December 31, 2005, was 6% of the total ownership of MGG, certain executive officers of our general partner also indirectly benefit from these distributions. In 2004 and 2005, distributions paid to our general partner totaled $16.7 million and $30.1 million, respectively. In addition, during 2004 and 2005, MGG received distributions totaling $28.7 million and $5.0 million, respectively, related to its common and subordinated units. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.5525 per unit, our general partner would receive distributions of approximately $51.4 million in 2006 on its combined 2% general partner interest and incentive distribution rights.

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" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to numerous assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document.

The following are among the important factors that could cause actual results to differ materially from any results projected, forecasted, estimated or budgeted:

- price fluctuations for natural gas liquids and refined petroleum products;
- overall demand for natural gas liquids, refined petroleum products, natural gas, oil and ammonia in the United States;
- weather patterns materially different than historical trends;
- development of alternative energy sources;
- changes in demand for storage in our petroleum products terminals;
- changes in supply patterns for our marine 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;

- changes in the throughput or interruption in service on petroleum products pipelines owned and operated by third parties and connected to our petroleum products terminals or petroleum products pipeline system;
- loss of one or more of our three customers on our ammonia pipeline system;
- an increase in the competition our operations encounter;
- the occurrence of an operational hazard or unforeseen interruption for which we are not adequately insured;
- the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- changes in general economic conditions in the United States;
- changes in laws or regulations to which we are subject, including tax withholding issues, safety, environmental and employment laws and regulations;
- 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 could have other adverse consequences;
- a change of control of our general partner, which could, under certain circumstances, result in our debt or the debt of our subsidiaries becoming due and payable;
- the condition of the capital markets in the United States;
- 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;
- Williams' and other third-parties' ability to pay the amounts owed to us under indemnification agreements;
- conflicts of interests between us, our general partner and MGG;
- the ability of our general partner or its affiliates to enter into certain agreements which could negatively impact our financial position, results of operations and cash flows;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

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 do not have foreign exchange risks. 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.

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risk to which we are exposed is interest rate risk. As of December 31, 2005, we had no variable interest debt outstanding; however, because of certain interest rate swap agreements discussed below, we are exposed to $350.0 million of interest rate market risk. If interest rates change by 0.25%, our annual interest expense would change by $0.9 million.

During May 2004, we entered into four separate interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline Series B senior notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the agreements, we receive 7.7% (the interest rate of the Magellan Pipeline Series B senior notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007. Payments settle in April and October of each year with LIBOR set in arrears.

During 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 have accounted for this interest rate hedge as a fair value hedge. The notional amount of the interest rate swap agreement is $100.0 million. Under the terms of the agreement, we receive 5.65% (the interest rate of the $250.0 million senior notes) and pay LIBOR plus 0.6%. This hedge effectively converts $100.0 million of our 5.65% fixed-rate debt to floating-rate debt. The interest rate swap agreement began on October 15, 2004 and expires on October 15, 2016. Payments settle in April and October of each year with LIBOR set in arrears.

As of December 31, 2005, we had entered into futures contracts for the acquisition of approximately 0.9 million barrels of petroleum products. The notional value of these agreements, with maturity dates during the first quarter of 2006, was approximately $65.8 million.

As of December 31, 2005, we had entered into futures contracts for the sale of approximately 0.3 million barrels of petroleum products. The notional value of these agreements, with maturity dates during the first quarter of 2006, was approximately $22.5 million.

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The term internal control over financial reporting is defined as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention and timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on our financial statements. Management believes that the design and operation of our internal control over financial reporting at December 31, 2005 are 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 ("COSO" criteria) of the Treadway Commission. As of December 31, 2005, based on the results of our assessment, management believes that we have no material weaknesses in internal control over our financial reporting. We maintained effective internal control over financial reporting as of December 31, 2005, 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 management's assessment of our internal control over financial reporting as of December 31, 2005. The report, which expresses unqualified opinions on management's assessment and on the effectiveness of our internal control over financial reporting as of December 31, 2005, is included below under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting."

By: /s/ DON R. WELLENDORF

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

Vice President, Treasurer 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 management's assessment, included in the accompanying "Management's Annual Report on Internal Control Over Financial Reporting," that Magellan Midstream Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the partnership's internal control over financial reporting based on our audit.

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

A company'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 company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the entity's assets that could have a material effect on the financial statements.

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

In our opinion, management's assessment that Magellan Midstream Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2005 is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005 based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2005 and 2004, and the related consolidated statements of income, cash flows and partners' capital for each of the three years in the period ended December 31, 2005 and our report dated March 8, 2006 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
March 8, 2006

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

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, 2005 and 2004, and the related consolidated statements of income, cash flows and partners' capital for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 8, 2006, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
March 8, 2006

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

	Year Ended December 31,		
	2003	2004	2005
Transportation and terminals revenues:			
Third party	$359,726	$419,117	$ 500,196
Affiliate	13,122	—	—
Product sales revenues:			
Third party	111,522	275,769	636,209
Affiliate	790	—	—
Affiliate management fee revenues	—	488	667
Total revenues	485,160	695,374	1,137,072
Costs and expenses:			
Operating	164,612	177,066	217,788
Environmental	14,089	43,989	12,007
Environmental reimbursements	(11,818)	(41,398)	—
Product purchases	99,907	255,599	582,631
Depreciation and amortization	36,081	41,845	56,307
Affiliate general and administrative	56,846	54,466	61,131
Total costs and expenses	359,717	531,567	929,864
Equity earnings	—	1,602	3,104
Operating profit	125,443	165,409	210,312
Interest expense	36,597	37,893	52,554
Interest income	(2,061)	(2,458)	(4,296)
Debt prepayment premium	—	12,666	—
Write-off of unamortized debt placement costs	—	5,002	—
Debt placement fee amortization	2,830	3,056	2,871
Other income	(92)	(953)	(300)
Net income	$ 88,169	$110,203	$ 159,483
Allocation of net income:			
Limited partners' interest	$ 90,191	$101,140	$ 135,579
General partner's interest	(2,022)	9,063	23,904
Net income	$ 88,169	$110,203	$ 159,483
Basic net income per limited partner unit	$ 1.66	$ 1.72	$ 2.04
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	54,390	58,716	66,361
Diluted net income per limited partner unit	$ 1.66	$ 1.72	$ 2.03
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	54,470	58,844	66,625

See notes to consolidated financial statements.

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

	December 31, 2004	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 29,833	$ 36,489
Restricted cash	5,847	5,537
Marketable securities	87,802	—
Accounts receivable (less allowance for doubtful accounts of $133 at December 31, 2004 and 2005)	36,054	49,373
Other accounts receivable	19,786	5,566
Affiliate accounts receivable	8,637	5,535
Inventory	43,397	78,155
Other current assets	6,385	5,034
Total current assets	237,741	185,689
Property, plant and equipment, at cost	1,956,884	2,116,143
Less: accumulated depreciation	463,266	506,626
Net property, plant and equipment	1,493,618	1,609,517
Equity investments	25,084	24,888
Long-term receivables	8,070	7,327
Long-term affiliate receivables	4,599	1,245
Goodwill	22,007	24,430
Other intangibles (less accumulated amortization of $2,211 and $3,607 at December 31, 2004 and 2005, respectively)	10,118	11,652
Debt placement costs (less accumulated amortization of $4,040 and $6,911 at December 31, 2004 and 2005, respectively)	10,954	8,084
Other noncurrent assets	5,641	3,686
Total assets	$1,817,832	$1,876,518
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 20,394	$ 25,508
Affiliate accounts payable	497	5,821
Affiliate payroll and benefits	19,275	17,028
Accrued interest payable	9,860	9,628
Accrued taxes other than income	16,632	17,307
Environmental liabilities	33,160	30,840
Deferred revenue	12,958	17,522
Accrued product purchases	17,313	34,772
Accrued product shortages	7,507	—
Current portion of long-term debt	15,100	14,345
Other current liabilities	13,308	13,124
Total current liabilities	166,004	185,895
Long-term debt	789,568	782,639
Long-term affiliate payable	6,578	10,091
Long-term affiliate pension and benefits	4,120	9,766
Other deferred liabilities	34,807	52,773
Environmental liabilities	27,646	27,364
Commitments and contingencies		
Partners' capital:		
Common unitholders (57,841 units and 60,681 units outstanding at December 31, 2004 and 2005, respectively)	1,058,913	1,097,391
Subordinated unitholders (8,520 units and 5,680 units outstanding at December 31, 2004 and 2005, respectively)	101,222	67,925
General partner	(369,104)	(355,271)
Accumulated other comprehensive loss	(1,922)	(2,055)
Total partners' capital	789,109	807,990
Total liabilities and partners' capital	$1,817,832	$1,876,518

See notes to consolidated financial statements.

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

	Year Ended December 31, 2003	2004	2005
Operating Activities:			
Net income	$ 88,169	$ 110,203	$ 159,483
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	36,081	41,845	56,307
Debt placement fee amortization	2,830	3,056	2,871
Debt prepayment penalty	—	12,666	—
Write-off of unamortized debt placement costs	—	5,002	—
Loss on sale and retirement of assets	4,563	5,164	8,334
Gain on interest rate hedge	—	(953)	—
Equity earnings	—	(1,602)	(3,104)
Distributions from equity investment	—	1,550	3,300
Changes in operating assets and liabilities (Note 4)	12,315	59,570	(2,389)
Net cash provided by operating activities	143,958	236,501	224,802
Investing Activities:			
Purchases of marketable securities	—	(320,205)	(50,500)
Sales of marketable securities	—	232,403	138,302
Additions to property, plant and equipment	(34,636)	(53,545)	(92,791)
Proceeds from sale of assets	4,034	1,794	2,994
Equity investments	—	(25,032)	—
Partial buyout of third-party supply agreement	—	—	(7,566)
Acquisitions of businesses	(15,346)	(25,441)	(55,263)
Acquisition of assets	—	(522,300)	(10,863)
Net cash used by investing activities	(45,948)	(712,326)	(75,687)
Financing Activities:			
Distributions paid	(90,527)	(116,943)	(160,494)
Borrowings under revolver	—	—	13,000
Borrowings under credit facility	90,000	50,000	—
Payments on credit facility	(90,000)	(140,000)	—
Borrowings under short-term notes	—	300,000	—
Payments on short-term notes	—	(300,000)	—
Borrowings under long-term notes	—	499,182	—
Payments on long-term notes	—	(178,000)	(15,100)
Capital contributions by affiliate	21,951	14,807	20,087
Sales of common units to public (less underwriters' commissions and payment of formation and offering costs)	9,477	286,523	—
Debt placement costs	(2,905)	(8,394)	—
Payment of debt prepayment premium	—	(12,666)	—
Net settlement of interest rate hedges	—	(208)	—
Other	200	—	48
Net cash provided by (used in) financing activities	(61,804)	394,301	(142,459)
Change in cash and cash equivalents	36,206	(81,524)	6,656
Cash and cash equivalents at beginning of period	75,151	111,357	29,833
Cash and cash equivalents at end of period	$111,357	$ 29,833	$ 36,489
Supplemental non-cash investing and financing transactions:			
Contributions by affiliate of property, plant and equipment and other assets and liabilities to partners' capital	$ 17,644	$ 2,396	$ —

See notes to consolidated financial statements.

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

	Common	Subordinated	Class B Common	General Partner	Accumulated Other Comprehensive Loss	Total Partners' Capital
Balance, January 1, 2003	$ 399,837	$131,194	$ 313,651	$(391,954)	$ (971)	$ 451,757
Comprehensive income:						
Net income	46,857	18,838	24,496	(2,022)	—	88,169
Amortization of loss on cash flow hedges	—	—	—	—	200	200
Total comprehensive income						88,369
Issuance of common units to public (0.4 million units)	9,477	—	—	—	—	9,477
Conversion of class B common units to common units (15.7 million units)	317,379	—	(317,379)	—	—	—
Affiliate capital contributions	6,322	2,557	3,364	27,352	—	39,595
Distributions	(41,929)	(17,409)	(24,001)	(7,188)	—	(90,527)
Other	(228)	(95)	(131)	(68)	—	(522)
Balance, December 31, 2003	737,715	135,085	—	(373,880)	(771)	498,149
Comprehensive income:						
Net income	86,136	15,004	—	9,063	—	110,203
Amortization of loss on cash flow hedges	—	—	—	—	9	9
Net loss on cash flow hedges	—	—	—	—	(1,160)	(1,160)
Total comprehensive income						109,052
Conversion of subordinated units to common units (2.8 million units)	33,024	(33,024)	—	—	—	—
Issuance of common units to public (11.6 million units)	286,523	—	—	—	—	286,523
Affiliate capital contributions	—	—	—	12,411	—	12,411
Distributions	(84,414)	(15,832)	—	(16,697)	—	(116,943)
Other	(71)	(11)	—	(1)	—	(83)
Balance, December 31, 2004	1,058,913	101,222	—	(369,104)	(1,922)	789,109
Comprehensive income:						
Net income	123,273	12,306	—	23,904	—	159,483
Amortization of loss on cash flow hedges	—	—	—	—	210	210
Additional minimum pension liability	—	—	—	—	(343)	(343)
Total comprehensive income						159,350
Conversion of subordinated units to common units (2.8 million units)	33,147	(33,147)	—	—	—	—
Affiliate capital contributions	—	—	—	20,087	—	20,087
Distributions	(117,942)	(12,456)	—	(30,096)	—	(160,494)
Other	—	—	—	(62)	—	(62)
Balance, December 31, 2005	$1,097,391	$ 67,925	$ —	$(355,271)	$(2,055)	$ 807,990

See notes to consolidated financial statements.

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

1. Organization and Basis of Presentation

Unless indicated otherwise, the terms "our," "we," "us" and similar language refer to Magellan Midstream Partners, L.P., together with our subsidiaries. We were formed in August 2000 as Williams Energy Partners L.P., a Delaware limited partnership, to own, operate and acquire a diversified portfolio of complementary energy assets. We were renamed Magellan Midstream Partners, L.P. effective September 1, 2003.

Change in Ownership of General Partner

On June 17, 2003, The Williams Companies, Inc. ("Williams") sold its ownership of our common, subordinated and class B common units and all of its membership interests of our general partner, including the incentive distribution rights, to WEG Acquisitions, L.P., a Delaware limited partnership formed by Madison Dearborn Capital Partners IV, L.P. and Carlyle/Riverstone Global Energy and Power Fund II, L.P. WEG Acquisitions, L.P. was renamed Magellan Midstream Holdings, L.P. ("MGG") effective September 1, 2003. During 2004 and 2005, MGG sold all of its limited partner ownership interests in us; however, MGG continues to own our 2% general partner interest and associated incentive distribution rights through its ownership of our general partner, Magellan GP, LLC.

Associated with this change in ownership of our general partner:

- An affiliate of Williams assigned its rights to and interest in the ATLAS 2000 software system and associated hardware to us.
- Williams and its affiliates terminated our services agreement, which provided the necessary employees to operate our assets. A services agreement with MGG was executed at that time, which, among other things, provided for the necessary employees to operate our assets. In return, we agreed to pay MGG for its direct and indirect expenses incurred in providing these services, subject to certain limitations on the reimbursement of general and administrative ("G&A") expense. This services agreement with MGG was terminated and we executed a new services agreement with Magellan Midstream Holdings GP, LLC ("MGG GP"), MGG's general partner, in December 2005. See Note 12—Related Party Transactions for a further discussion of these items.
- Williams, certain of Williams' affiliates and MGG entered into a new omnibus agreement, to which we are a third-party beneficiary. In this agreement, Williams and certain of its affiliates agreed to indemnify us for certain environmental losses. Additionally, Williams made certain other indemnifications to us upon closing of the sale of its ownership interest in us. Certain of these indemnifications were settled with Williams during 2004 (see Note 18—Commitments and Contingencies for a discussion of this matter). Williams and certain of its affiliates further agreed to indemnify us for right-of-way defects or failures in the ammonia pipeline easements and right-of-way defects or failures associated with the marine terminals at Galena Park and Corpus Christi, Texas and Marrero, Louisiana until February 2016.
- Additionally, MGG agreed to assume certain of Williams' environmental indemnification obligations to us for $21.9 million.
- MGG assumed sponsorship of a union pension plan for certain employees on January 1, 2004. MGG transferred this plan to MGG GP in December 2005 (see Note 11-Employee Benefit Plans for a discussion of this matter).

Operating Segments

We own a petroleum products pipeline system, petroleum products terminals and an ammonia pipeline system.

Petroleum Products Pipeline System. Our petroleum products pipeline system includes 8,500 miles of pipeline and 45 terminals that provide transportation, storage and distribution services. Our petroleum products 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, diesel fuels, LPGs and aviation fuels. 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, airlines and other end-users. As part of a pipeline system acquisition completed during October 2004, we assumed an agreement to supply petroleum products to a customer in the west Texas markets. The purchase, transportation and resale of petroleum products associated with this supply agreement are included in the petroleum products pipeline segment. We acquired an ownership interest in Osage Pipeline Company, LLC ("Osage Pipeline") during 2004. This system includes the 135-mile Osage pipeline, which transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to National Cooperative Refining Association's ("NCRA") refinery in McPherson, Kansas and the Frontier refinery in El Dorado, Kansas. In July 2003, we acquired a petroleum products blending operation which is also included in the petroleum products pipeline system segment.

Petroleum Products Terminals. Most of our petroleum products terminals are strategically located along or near third-party pipelines or petroleum refineries. The petroleum products terminals provide a variety of services such as distribution, storage, blending, inventory management and additive injection to a diverse customer group including governmental customers and end-users in the downstream refining, retail, commercial trading, industrial and petrochemical industries. Products stored in and distributed through the petroleum products terminal network include refined petroleum products, blendstocks and heavy oils and feedstocks. The terminal network consists of marine terminals and inland terminals. In September 2005, we acquired a refined petroleum products terminal in Wilmington, Delaware (see Note 6—Acquisitions), increasing the number of marine terminals we operate to seven. Five of our marine terminal facilities are located along the Gulf Coast and two marine terminal facilities are located on the East Coast. As of December 31, 2005, we owned 29 inland terminals located primarily in the southeastern United States.

Ammonia Pipeline System. The ammonia pipeline system consists of an ammonia pipeline and six company-owned terminals. Shipments on the pipeline primarily originate from ammonia production plants located in Borger, Texas and Enid and Verdigris, Oklahoma for transport to terminals throughout the Midwest. The ammonia transported through the system is used primarily as nitrogen fertilizer.

2. Summary of Significant Accounting Policies

Basis of Presentation. The consolidated financial statements include the petroleum products pipeline system, the petroleum products terminals and the ammonia pipeline system. All intercompany transactions have been eliminated.

In March 2005, the board of directors of our general partner approved a two-for-one split of our limited partner units. According to the provisions of Financial Accounting Standards Board ("FASB") Statement No. 128, *Earnings Per Share*, we have retroactively changed the number of our limited partner units and the net income and distribution per limited partner unit amounts to give effect for this two-for-one split for all periods presented in this report.

Reclassifications. Certain previously reported balances for 2004 have been classified differently to conform to current year presentation. Net income was not affected by these reclassifications. Reclassifications were as follows:

	Previous 10-K Report	Current 10-K Report	Difference
Statement of Income			
Transportation revenues	$ 416,408	$ 419,117	$ 2,709
Product sales revenues	278,478	275,769	(2,709)
Operating expenses	176,941	177,066	125
Product purchases	255,724	255,599	(125)
Balance Sheet			
Accounts receivable	35,631	36,054	423
Other accounts receivable	20,209	19,786	(423)
Statement of Cash Flows			
Investing Activities:			
Acquisition of assets	(524,460)	(522,300)	2,160
Additions to property, plant and equipment	(51,385)	(53,545)	(2,160)

The statement of income reclassifications related to transportation revenues and operating expenses associated with our third-party supply agreement which were incorrectly classified as product sales and product purchases. The balance sheet reclassification is a receivable from an insurance carrier that was improperly classified as a trade receivable. The cash flow reclassifications resulted from accruals for transaction costs that were different from actual costs incurred.

Use of Estimates. The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States 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 the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

Regulatory Reporting. Our petroleum products 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 generally accepted accounting principles ("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.

Restricted Cash. Restricted cash includes cash held by us pursuant to the terms of the Magellan Pipeline Company, L.P. ("Magellan Pipeline") notes (see Note 13—Debt).

Marketable Securities. Marketable securities consist of highly liquid debt securities with a maturity of greater than three months when purchased. Investments were classified in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments in Debt and Equity Securities". Our marketable securities were classified as "available-for-sale" and were reported at fair value with related unrealized gains and losses in the value of such securities recorded as a component of partners' capital until realized. All of our marketable securities were liquidated during 2005. There were no unrealized gains or losses on our marketable securities at December 31, 2004.

At December 31, 2004, marketable securities, determined on a specific identification method, were $87.8 million, which consisted of $55.6 million of auction-rate preferred securities and $32.2 million of asset-backed notes. Interest rates on these AAA-rated securities were set in auction every 7 to 28 days, limiting our exposure to interest rate risk. These securities had various ultimate maturities, most of which were greater than 10 years.

Inventory Valuation. Inventory is comprised primarily of refined petroleum products, natural gas liquids and additives, which are stated at the lower of average cost or market.

Trade Receivables and Allowance for Doubtful Accounts. Trade receivables represent valid claims against non-affiliated customers and are recognized when products are sold or services are rendered. We extend credit terms to certain customers based on historical dealings and to other customers after a review of various credit indicators, including the customers' credit rating. An allowance for doubtful accounts is established for all or any portion of an account where collections are considered to be at risk and reserves are evaluated 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. Trade receivables are written off when the account is deemed uncollectible.

Property, Plant and Equipment. Property, plant and equipment consist primarily of pipeline, pipeline-related equipment, storage tanks and terminal facility equipment and are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired.

Assets are depreciated individually on a straight-line basis over their useful lives. We assign these lives based on reasonable estimates when the asset is placed into service. Subsequent events could cause us to change our estimates, which would impact the future calculation of depreciation expense. The depreciation rates for most of our pipeline assets are approved and regulated by the FERC. Assets with the same useful lives and similar characteristics are depreciated using the same rate. The individual components of certain assets, such as tanks, are grouped together into a composite asset. Those assets are depreciated using a composite rate. The range of depreciable lives by asset category is detailed in Note 8—Property, Plant and Equipment.

The cost of property, plant and equipment sold or retired and the related accumulated depreciation is removed from the accounts and any associated gains or losses are recorded in the income statement in the period of sale or disposition.

Expenditures to replace existing assets are capitalized and the replaced assets are retired. Expenditures associated with existing assets are capitalized when they improve the productivity or increase the useful life of the asset. Expenditures for maintenance, repairs and minor replacements are charged to operating expense in the period incurred. We capitalize direct 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 capitalize interest for capital projects with expenditures over $0.5 million that require three months or longer to complete.

Asset Retirement Obligation. We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" effective January 1, 2003. SFAS No. 143 requires the fair value of a liability related to the retirement of long-lived assets to be recorded at the time a legal obligation is incurred, if the liability can be reasonably estimated. When the liability is initially recorded, the carrying amount of the related asset is increased by the same amount. Over time, the liability is accreted to its future value, with the accretion recorded to expense. In

March 2005, the FASB issued Interpretation ("FIN") No. 47, "Accounting for Conditional Asset Retirement Obligations (as amended)." FIN No. 47 clarified that where there is an obligation to perform an asset retirement activity, even though uncertainties exist about the timing or method of settlement, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be determined.

Our operating assets generally consist of underground refined products pipelines and related facilities along rights-of-way and above-ground storage tanks and related facilities. Our rights-of-way agreements typically do not require the dismantling, removal and reclamation of the rights-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 $0.8 million liability associated with anticipated tank liner replacements, we have recorded no liability or corresponding asset in conjunction with SFAS No. 143 and FIN No. 47 because both the amounts and future dates of when such costs might be incurred are indeterminable.

Equity Investments. We account for investments greater than 20% in affiliates, which we do not control, by the equity method of accounting. Under this method, an investment is recorded at our acquisition cost, plus our equity in undistributed earnings or losses since acquisition, less distributions received and less amortization of excess net investment. Excess investment is the amount by which our initial investment exceeds our proportionate share of the book value of the net assets of the investment. We evaluate equity method investments for impairment annually or whenever events or circumstances indicate that there is a loss in value of the investment which is other-than-temporary. 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 recorded no equity investment impairments during 2003, 2004 or 2005.

Goodwill and Other Intangible Assets. We have adopted SFAS No. 142, "Goodwill and Other Intangible Assets." In accordance with this Statement, beginning on January 1, 2002, goodwill, which represents the excess of cost over fair value of assets of businesses acquired, is no longer amortized but is evaluated periodically for impairment. Goodwill at December 31, 2004 and 2005 was $22.0 million and $24.4 million, respectively. The increase in goodwill was due to goodwill recognized from our acquisition of the Wilmington, Delaware terminal in September 2005, partially offset by amounts recorded for a contingent purchase price adjustment associated with a terminal acquired in 2001.

The determination of whether goodwill is impaired is based on management's estimate of the fair value of our reporting units as compared to their carrying values. Critical assumptions used in our estimates included: (i) time horizon of 20 years, (ii) revenue growth of 2.5% per year and expense growth of 3.0% per year, except for depreciation expense growth of 1% per year, (iii) weighted-average cost of capital of 9.0% based on assumed cost of debt of 6%, assumed cost of equity of 12.0% and a 50%/50% debt-to-equity ratio, and (iv) 8 times EBITDA multiple for terminal value. We selected October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2003, 2004 or 2005. If impairment were to occur, the amount of the impairment recognized would be determined by subtracting the implied fair value of the reporting unit goodwill from the carrying amount of the goodwill.

Other intangible assets are amortized on a straight-line basis over their estimated useful lives of 5 years up to 25 years. Amortization of other intangible assets was $0.8 million, $1.3 million and $1.4 million during 2003, 2004 and 2005, respectively.

Judgments and assumptions are inherent in management's estimates used to determine the fair value of our operating segments. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Impairment of Long-Lived Assets. In January 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." In accordance with this Statement, 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. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment were to occur, the amount of the impairment recognized would be calculated 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.

Long-lived assets to be disposed of through sales of assets that meet specific criteria are classified as "held for sale" and are recorded 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.

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. We recorded no impairments relative to our long-lived assets during 2003, 2004 or 2005.

Lease Financings. Direct financing leases are accounted for such that the minimum lease payments plus the unguaranteed residual value accruing to the benefit of the lessor is recorded as the gross investment in the lease. The net investment in the lease is the difference between the total minimum lease payment receivable and the associated unearned income.

Debt Placement Costs. Costs incurred for debt borrowings are capitalized as paid and amortized over the life of the associated debt instrument using the effective interest method. When debt is retired before its scheduled maturity date, any remaining placement costs associated with that debt are written off.

Capitalization of Interest. Interest on borrowed funds is capitalized on projects during construction based on the approximate average interest rate of our debt. We capitalize interest on all construction projects requiring three months or longer to complete with total costs exceeding $0.5 million. Capitalized interest for the years ended December 31, 2003, 2004 and 2005 was $0.1 million, $0.4 million and $0.8 million, respectively.

Pension and Post-Retirement Medical and Life Benefit Obligations. Beginning January 1, 2004, MGG maintained defined benefit plans and a defined contribution plan, which provided retirement benefits to substantially all of its employees. In December 2005, the employees of MGG were transferred to MGG GP and accordingly the defined benefit plans and defined contribution plan were also transferred to MGG GP (see Note 11—Employee Benefit Plans). The affiliate pension and post-retirement medical and life liabilities reported on our consolidated balance sheets represent the funded status of the present value of benefit obligations net of unrecognized prior service costs/credits and unrecognized actuarial gains/losses of the aforementioned plans.

Paid-Time Off Benefits. Affiliate liabilities for paid-time off benefits are recognized for all employees performing services for us when earned by those employees. We recognized affiliate paid-time off liabilities of $6.2 million and $6.8 million at December 31, 2004 and 2005, respectively. These balances represent the remaining vested paid-time off benefits of employees who support us. Affiliate liabilities for paid-time off are reflected in the accrued affiliate payroll and benefits balances of the consolidated balance sheets.

Derivative Financial Instruments. We account for hedging activities in accordance with SFAS No. 133, "Accounting for Financial Instruments and Hedging Activities", SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133" and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." These statements establish accounting and reporting standards requiring that derivative instruments be recorded 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 each instrument's intended use and how it is designated. Derivative financial instruments qualifying for hedge accounting treatment can generally be divided into two categories: (1) cash flow hedges and (2) fair value hedges. Cash flow hedges are executed to hedge the variability in cash flows related to a forecasted transaction. Fair value hedges are executed to hedge 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 hedge item. Furthermore, we assess the creditworthiness of the counterparties to manage against the risk of default. If we determine that a derivative, originally designed as a cash flow or fair value hedge, is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

Derivatives that qualify for and for which we designate as normal purchases and sales are exempted from the fair value accounting requirements of SFAS No.'s 133, 138 and 149 and are accounted for using traditional accrual accounting. As of December 31, 2005, we had commitments under future contracts for product purchases that will be accounted for as normal purchases totaling approximately $65.8 million. Additionally, we had commitments under future contracts for product sales that will be accounted for as normal sales totaling approximately $22.5 million.

We generally report gains, losses and any ineffectiveness from interest rate derivatives in our results of operations separately. We recognize the effective portion of hedges against changes in interest rates as adjustments to other comprehensive income. We record the non-current portion of unrealized gains or losses associated with fair value hedges on long-term debt as adjustments to long-term debt on the balance sheet with the current portion recorded as adjustments to interest expense.

The derivative gains and losses and minimum pension liabilities included in other comprehensive income is as follows (in thousands):

	Derivative Gains (Losses)	Minimum Pension Liability	Total Other Comprehensive Income
Balance, January 1, 2003	$ (971)	$ —	$ (971)
Amortization of loss on cash flow hedges	200	—	200
Balance, December 31, 2003	(771)	—	(771)
Amortization of loss on cash flow hedges	9	—	9
Net loss on cash flow hedges	(1,160)	—	(1,160)
Balance, December 31, 2004	(1,922)	—	(1,922)
Amortization of loss on cash flow hedges	210	—	210
Additional minimum pension liability	—	(343)	(343)
Balance, December 31, 2005	$(1,712)	$(343)	$(2,055)

Revenue Recognition. Petroleum pipeline and ammonia transportation revenues are recognized when shipments are complete. Injection service fees associated with customer proprietary additives are recognized upon injection to the customer's product, which occurs at the time the product is delivered. Leased tank storage, pipeline capacity leases, terminalling, throughput, ethanol loading and unloading services, laboratory testing and data services, pipeline operating fees and other miscellaneous service-related revenues are recognized upon completion of contract services. Product sales are recognized upon delivery of the product to our customers.

Variable-Rate Terminalling Agreement. We had a terminalling agreement with a third-party customer under which we provided storage rental and throughput fees based on discounted rates plus a variable fee, which was based on a percentage of the net profits from certain trading activities conducted by our customer. Under this agreement which expired on January 31, 2006, we recognized the storage rental and throughput fees as the services were performed; however, we would not receive revenue from the variable fee if the net trading profits fell below a specified amount or were negative. Therefore, the revenue we earned related to the shared trading profits was not determinable until the end of the contract term, and we elected to defer the recognition of this revenue until the end of the contract term.

Buy / Sell Arrangements. To help manage the supply of inventory and provide specific quantities and grades of products at various locations on our systems, we engage in certain buy / sell arrangements. We are the primary obligor on these transactions and we assume credit risk and risk of ownership for the associated products. Accordingly, under Emerging Issues Task Force ("EITF") Issue No. 99-19, "Recording Revenue Gross as a Principle Versus Net as an Agent" we have included the gross amounts of these transactions in our consolidated statements of income. Amounts associated with these buy / sell arrangements included in product sales revenues and in product purchases on our 2004 and 2005 consolidated financial statements were $23.1 million and $2.4 million, respectively. During 2005, the EITF reached a tentative conclusion, which is required to be applied to transactions completed in reporting periods beginning after March 15, 2006, that will require us to report these product sales net of product purchases. Had these transactions been reported net, our product sales and product purchases during 2004 and 2005 would have been reduced by $23.1 million and $2.4 million, respectively.

G&A Expenses. Prior to MGG's acquisition of Williams' interests in us on June 17, 2003, we recorded G&A expenses up to the amount of the G&A expense limitation as agreed to between us, our general partner and Williams and its affiliates. Under the organization structure put in place after June 17, 2003, we could clearly identify all G&A costs required to support our operations and have recognized these costs as G&A expense in our income statement. Since June 17, 2003, the amount of G&A expense above the expense limitation, as defined in the new omnibus agreement, has been recognized as a capital contribution by our general partner and the associated expense is specifically allocated to our general partner.

Unit-Based Incentive Compensation Awards. Our general partner has issued incentive awards of phantom units representing limited partner interests in us to certain employees of MGG GP who support us. These awards are accounted for using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." Since the grant price of the incentive unit awards made by our general partner is less than the market price of the underlying units, we recognize compensation expense associated with these awards. Compensation cost is recognized over the vesting period of the awards based on either the current market value of our common units at each period end or the market price of the common units at the measurement date, whichever is appropriate. The measurement date for determining compensation costs in our award plan is the first date on which we know the number of units that an employee is entitled to receive.

Certain unit awards include performance and other provisions, which can result in payouts to the recipients of from zero up to double the amount of the award. Additionally, certain awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out, historically by as much as 20% to 40%. Judgments and assumptions of the final award payouts are inherent in the accruals we record for unit-based incentive compensation costs. The use of alternate judgments and assumptions could result in the recognition of different levels of unit-based incentive compensation costs in our financial statements.

Environmental. Environmental expenditures that relate to current or future revenues are expensed or capitalized based upon the nature of the expenditures. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments are probable and the costs can be reasonably estimated. Environmental liabilities are recorded 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 consider our prior remediation experience and include an estimate for costs such as fees paid to contractors and outside engineering, consulting and law firms. Furthermore, costs include compensation and benefit expense of internal employees directly involved in remediation efforts. We maintain selective insurance coverage, which may cover all or portions of certain environmental expenditures. Receivables are recognized in cases where the realization of reimbursements of remediation costs is considered probable.

We have determined that certain costs would have been covered by indemnifications from Williams, which we have settled (see Note 18—Commitments and Contingencies). We make judgments on what would have been covered by these indemnifications and specifically allocate these costs to our general partner. We will record capital contributions from our general partner for amounts we receive from Williams pursuant to the indemnification settlement.

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 in our financial statements.

Income Taxes. We are not a taxable entity for federal and state income tax purposes. Accordingly, no recognition has been given to income taxes for financial reporting purposes. 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 as a result 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 in us is not available to us.

Allocation of Net Income. Except for those periods when net income exceeds distributions, net income is allocated to our general partner and limited partners based on the proportion of their contractually-determined cash distributions declared and paid following the close of each quarter (see Note 21—Distributions). Our general partner is also directly charged with specific costs that it has individually assumed and for which the limited partners are not responsible (see Note 5—Allocation of Net Income). For periods where net income exceeds distributions, net income is allocated to our general and limited partners based on their proportionate share of pro forma cash distributions assuming that distributions for the period were equal to net income, with adjustments made for any charges specifically allocated to our general partner.

Earnings Per Unit. Basic net income per unit is determined by dividing the limited partner's allocation of net income by the weighted average number of common and subordinated units outstanding for the period. Diluted net income per unit is the same calculation, except the weighted average units outstanding include any dilutive effect of phantom unit grants.

Comprehensive Income. We account for comprehensive income in accordance with SFAS No. 130, "Reporting Comprehensive Income." Our comprehensive income is determined based on net income adjusted for changes in other comprehensive income (loss) from our derivative hedging transactions, related amortization of realized gains/losses and minimum pension liabilities. SFAS No. 130 requires us to report total comprehensive income, which we have included with our consolidated statement of partners' capital.

Recent Accounting Standards. In November 2005, the FASB issued FASB Staff Position ("FSP") No. FAS 115-1 and FAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments." This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary and the measurement of an impairment loss. This FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities," FASB Statement No. 124, "Accounting for Certain Investments Held by Not-for-Profit Organizations," and APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The guidance in this FSP is to be applied to reporting periods beginning after December 15, 2005. We adopted this FSP on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In October 2005, the FASB issued FSP No. 13-1, "Accounting for Rental Costs Incurred During a Construction Period." This FSP requires entities who incur rental costs associated with operating leases to expense such costs as a continuing operating expense. This FSP is required to be implemented beginning January 1, 2006, with early adoption permitted. We adopted the FSP on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In September 2005, the FASB issued EITF No. 04-13, "Accounting for Purchases and Sales of Inventory With the Same Counterparty." In EITF No. 04-13, the FASB reached a tentative conclusion that inventory purchases and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying Accounting Principles Board Opinion No. 29, "Accounting for Nonmonetary Transactions." The tentative conclusions reached by the FASB are required to be applied to transactions completed in reporting periods beginning after March 15, 2006. The adoption of this EITF will not have a material impact on our results of operations, financial position or cash flows.

In May 2005, the FASB published SFAS No. 154, "Accounting Changes and Error Corrections." SFAS No. 154 requires retrospective application to prior periods' financial statements of every voluntary change in accounting principle unless it is impracticable to do so. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in nondiscretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change. We adopted SFAS No. 154 in January 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In March 2005, the FASB issued FIN No. 47, "Accounting for Conditional Asset Retirement Obligations (as amended)." This Interpretation clarified that the term *conditional asset retirement obligation* as used in SFAS No. 143, "Accounting for Asset Retirement Obligations," refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. SFAS No. 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN No. 47 was required to be adopted no later than the end of fiscal years ending after December 15, 2005, with retrospective application for interim financial information permitted. We adopted FIN No. 47 in 2005, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In December 2004, the FASB issued a revision to SFAS No. 123, "Share-Based Payment," referred to as "SFAS No. 123R." Additionally, in October 2005, the FASB issued FSP 123(R)–2, "Practical Accommodation to the Application of Grant Date as Defined in FASB Statement No. 123(R)." This Statement and subsequent revisions establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. This SFAS requires that all equity-based compensation awards to employees be recognized in the income statement based on their fair values, eliminating the alternative to use APB No. 25's intrinsic value method. SFAS No. 123(R) is effective as of the beginning of the first interim period that begins after December 31, 2005. SFAS No. 123(R) applies to all awards granted after the required effective date but is not to be applied to awards granted in periods before the required effective date except to the extent that awards from prior periods are modified, repurchased or cancelled after the required effective date. We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method. Under the modified prospective method, we were required to account for all of our equity-based incentive awards granted prior to January 1, 2006, using the fair value method as defined in SFAS No. 123 instead of our current methodology of using the intrinsic value method as defined in APB No. 25. Due to the structure of our awards, we recognize compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123. Consequently, for the awards granted prior to January 1, 2006, the initial adoption and application of SFAS No. 123(R) did not have a material impact on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an Amendment of APB No. 29." The guidance in APB No. 29, "Accounting for Nonmonetary Transactions," is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance, however, included certain exceptions to that principle. This SFAS amends APB No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS No. 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The initial adoption and application of SFAS No. 153 did not have a material impact on our financial position, results of operations or cash flows.

In May 2004, the FASB issued FSP No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Prescription Drug Act")." FSP No. 106-2 superseded FSP No. 106-1, issued in January 2004. FSP No. 106-2 provides accounting guidance for employers that sponsor post-retirement health care plans which provide prescription drug benefits and receive the subsidy available under the Prescription Drug Act. FSP No. 106-2 also provides disclosure requirements about the effects of the subsidy for companies that offer prescription drug benefits. FAS No. 106-2 was effective on July 1, 2004 and did not have a material impact on our financial position, results of operations or cash flows during 2004.

In March 2004, the FASB issued EITF Statement No. 03-06, "Participating Securities and the Two-Class Method under SFAS No. 128, Earnings Per Share." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by entities that have issued securities other than common units that contractually entitle the holder to participate in distributions and earnings of the company when, and if, it declares distributions on its common units. EITF No. 03-06 also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF No. 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF No. 03-06 did not result in a change in our earnings per unit for any of the periods presented.

3. Debt and Equity Offerings

In August 2003, we entered into a new term loan and the $90.0 million we borrowed under that loan was used to repay the $90.0 million outstanding on our previous term loan and revolving credit facility. We incurred debt placement fees of $2.6 million associated with this transaction.

In December 2003, we issued 0.4 million common units representing limited partner interests in us at a price of $25.00 per unit for total proceeds of $10.0 million. Associated with this offering, our general partner contributed $0.2 million to us to maintain its 2% general partner interest. Of the proceeds received, $0.4 million was used to pay underwriting discounts and commissions. Legal, professional and other costs directly associated with this offering were approximately $0.1 million. The remaining cash proceeds of $9.7 million were used for general partnership purposes.

During May 2004, we executed a refinancing plan to improve our credit profile and increase our financial flexibility by removing all of the secured debt from our capital structure. The proceeds and use of cash from the transactions associated with this refinancing plan were as follows:

- Total proceeds from our 2.0 million common unit equity offering at a price of $23.80 per unit were $47.6 million. Associated with this offering, our general partner contributed $1.0 million to us to maintain its 2% general partner interest. Of the proceeds received, \$2.0 million was used to pay underwriting discounts and commissions. Legal, professional and other costs associated with the equity offering were approximately \$0.2 million.

- Total proceeds from the note issuance were \$249.5 million. Of the proceeds received, \$1.8 million was used to pay underwriting discounts and commissions and \$0.8 million was used to pay legal, professional and other fees.
- We used the net proceeds of \$293.3 million from these two offerings as follows:
  - repaid all of the outstanding \$178.0 million principal amount of Series A senior notes (see Note 13—Debt for a description of these notes) issued by Magellan Pipeline;
  - paid \$12.7 million of prepayment premiums associated with the early repayment of the Magellan Pipeline notes;
  - repaid the \$90.0 million outstanding principal balance of our then outstanding term loan;
  - paid \$1.9 million to Magellan Pipeline's Series B noteholders (see Note 13—Debt for a description of these notes) to release the collateral held by them and \$0.8 million of associated legal costs;
  - paid \$0.9 million of legal and professional fees associated with establishing a new unsecured revolving credit facility (see Note 13—Debt for a description of this facility); and
  - partially replenished the cash used to fund acquisitions completed in 2003 and early 2004.

In conjunction with the repayment of the Magellan Pipeline Series A senior notes and our term loan in May 2004, we recognized \$5.0 million of expense associated with the write-off of unamortized debt placement costs.

On October 1, 2004, we completed an acquisition of assets from Shell Pipeline Company LP and Equilon Enterprises LLC doing business as Shell Oil Products US (collectively "Shell") (see Note 6—Acquisitions). The debt and equity offerings discussed below were completed as part of the financing requirements associated with that acquisition:

- During August 2004, in anticipation of the acquisition, we issued and sold 3.6 million common units representing limited partner interests in us. Total proceeds from the sale, at a price of \$24.89 per unit, were \$89.6 million. Associated with this offering, our general partner made a \$1.8 million contribution to us to maintain its 2% general partner interest. Net proceeds after underwriter discounts of \$3.8 million and offering expenses of approximately \$0.5 million were \$87.1 million;
- On October 1, 2004, we borrowed \$300.0 million under a short-term acquisition facility and \$50.0 million under our revolving credit facility to help finance this acquisition. We incurred debt issuance costs of \$0.1 million associated with the \$300.0 million short-term acquisition facility;
- On October 4, 2004, we issued and sold 5.2 million common units representing limited partner interests in us. The units were sold at a price of \$27.25 for total proceeds of \$141.7 million. Associated with this offering, our general partner contributed \$2.9 million to us to maintain its 2% general partner interest. Of the proceeds received, \$6.0 million was used to pay underwriting discounts and commissions. Legal, professional and other costs associated with the equity offering were approximately \$0.3 million. We used the net proceeds of \$138.3 million to repay a portion of the amounts borrowed under the short-term acquisition facility. The underwriters exercised their over-allotment option associated with the October 2004 offering and on November 1, 2004, we issued and sold an additional 0.8 million common units. Total proceeds from this sale were \$21.3 million, of which we paid \$0.9 million for underwriting discounts and commissions. Our general partner made an additional \$0.4 million contribution to maintain its 2% general partner interest. The net proceeds of \$20.8 million from the over-allotment sale were used to replace cash we used to pay for other investments; and

- On October 15, 2004, we issued $250.0 million of senior notes. The notes were issued for the discounted price of 99.9%, or $249.7 million. The net proceeds from this debt issuance, after underwriter discounts of $1.8 million and debt issuance fees of $0.3 million, were $247.6 million. We used these net proceeds to: (i) repay the remaining $161.7 million outstanding under the acquisition facility (the original $300.0 million borrowed less $138.3 million partial repayment from the October 4, 2004 equity offering discussed above) plus accrued interest costs of $0.2 million, and (ii) repay the $50.0 million amount previously borrowed under the revolver plus accrued interest costs of $0.1 million. The remaining proceeds of $35.6 million from this debt offering were used to replenish cash used in the acquisition of assets from Shell.

In October 2005, we made a scheduled payment of $15.1 million on our Magellan Pipeline notes (see Note 13—Debt for further discussion of this matter). Also, during the fourth quarter of 2005, we borrowed $13.0 million on our revolving credit facility for working capital purposes.

4. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2003	2004	2005
Accounts receivable and other accounts receivable	$ (6,096)	$(21,646)	$ 901
Affiliate accounts receivable	3,040	687	3,102
Inventory	(6,812)	3,864	(34,758)
Accounts payable	3,938	(380)	5,114
Affiliate accounts payable	(9,977)	158	5,208
Affiliate payroll and benefits	8,260	4,532	(2,247)
Accrued interest payable	4,131	1,664	(232)
Accrued taxes other than income	589	(1,074)	1,028
Accrued product purchases	8,660	5,728	17,459
Accrued product shortages	—	7,507	(7,507)
Restricted cash	(3,281)	2,376	310
Cash collateral	—	14,000	(1,500)
Current and noncurrent environmental liabilities	4,485	27,894	(3,006)
Other current and noncurrent assets and liabilities	5,378	14,260	13,739
Total	$12,315	$ 59,570	$ (2,389)

5. Allocation of Net Income

The allocation of net income between our general partner and limited partners is as follows (in thousands):

	2003	2004	2005
Allocation of net income to general partner:			
Net income	$ 88,169	$110,203	$159,483
Direct charges to general partner:			
Write-off of property, plant and equipment	1,788	—	—
G&A portion of paid-time off accrual	2,108	—	—
Transition charges	1,233	823	—
Reimbursable G&A costs	5,974	6,397	3,294
Previously indemnified environmental charges	—	1,351	8,502
Total direct charges to general partner	11,103	8,571	11,796
Income before direct charges to general partner	99,272	118,774	171,279
General partner's share of income	9.15%	14.85%	20.84%
General partner's allocated share of net income before direct charges	9,081	17,634	35,700
Direct charges to general partner	(11,103)	(8,571)	(11,796)
Net income (loss) allocated to general partner	$ (2,022)	$ 9,063	$ 23,904
Net income	$ 88,169	$110,203	$159,483
Less: net income (loss) allocated to general partner	(2,022)	9,063	23,904
Net income allocated to limited partners	$ 90,191	$101,140	$135,579

The write-off of property, plant and equipment relates to Magellan Pipeline's asset balances prior to our acquisition of it; as a result, the charges from these write-offs were allocated directly to our general partner. The G&A portion of paid-time off expense accrual and the reimbursable G&A costs represent G&A expenses charged against our income during the periods presented that were required to be reimbursed to us by our general partner under the terms of the new omnibus agreement. Because the limited partners do not share in these costs, we have allocated these G&A expense amounts directly to our general partner. The transition charges represented our costs for transitioning from Williams to a stand-alone enterprise in excess of the amount we were contractually required to pay. Consequently, we have allocated all of these costs directly to our general partner. We record the reimbursements by our general partner as capital contributions. During 2004, we and our general partner entered into an agreement with Williams to settle certain of Williams' indemnification obligations to us (see Note 18—Commitments and Contingencies). Following this settlement, the expenses associated with these previously indemnified costs are allocated directly to our general partner. We believe we will collect the full amount of the indemnification settlement from Williams and accordingly will continue to allocate amounts associated with previously indemnified costs to our general partner.

6. Acquisitions

The acquisitions discussed below were accounted for as acquisitions of businesses. These acquisitions were accounted for under the purchase method and the assets acquired and liabilities assumed were recorded at their estimated fair market values as of their respective acquisition dates.

Petroleum Products Terminals

On January 29, 2004, we acquired ownership in 14 petroleum products terminals located in the southeastern United States. The results of operations from this acquisition have been included with the petroleum products terminals segment results since its acquisition date. We paid $24.8 million for these facilities, incurred $0.6 million of closing costs and assumed $3.8 million of environmental liabilities. We previously owned a 79% interest in eight of these terminals and purchased the remaining ownership interest from Murphy Oil USA, Inc. In addition, the acquisition included sole ownership of six terminals that were previously jointly owned by Murphy Oil USA, Inc. and Colonial Pipeline Company. The allocation of the purchase price to assets acquired and liabilities assumed was as follows (in thousands):

Purchase price:	
Cash paid, including transaction costs	$25,441
Environmental liabilities assumed	3,815
Total purchase price	$29,256
Allocation of purchase price:	
Property, plant and equipment	$29,256

On September 1, 2005, we acquired a refined petroleum products terminal near Wilmington, Delaware from privately-owned Delaware Terminal Company. This marine terminal has 1.8 million barrels of usable storage capacity. Management believes this facility is strategic to our efforts for growth and in providing expanded services for our customers' needs in the Mid-Atlantic markets. The operating results of this facility have been included with our petroleum products terminals segment results beginning on September 1, 2005. The land on which the facility sits was purchased in a separate transaction from a local non-profit agency. The preliminary allocation of the purchase price was as follows (in thousands):

Purchase price:	
Cash paid, including transaction costs	$55,263
Environmental liabilities assumed	250
Total purchase price	$55,513
Allocation of purchase price:	
Property, plant and equipment	$51,231
Goodwill	2,782
Other intangibles	1,500
Total	$55,513

The purchase price could change based on the completion of our evaluation and assessment of the assumed environmental liabilities. We expect that the total amount of goodwill recognized as part of this transaction will be deductible for tax purposes by our unitholders.

Pro Forma Information (unaudited)

The following summarized pro forma consolidated income statement information for the years ended December 31, 2004 and 2005 assumes that the petroleum product terminals acquisitions discussed above had occurred as of January 1, 2004. We have prepared these pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if we had completed these acquisitions as of the periods shown below or the results that will be attained in the future. The amounts presented below are in thousands, except per unit amounts:

	Year Ended December 31, 2004			Year Ended December 31, 2005		
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$695,374	$ 8,903	$704,277	$1,137,072	$ 5,585	$1,142,657
Net income	$110,203	$ 3,881	$114,084	$ 159,483	$ 2,508	$ 161,991
Basic net income per limited partner unit	$ 1.72	$ 0.06	$ 1.78	$ 2.04	$ 0.03	$ 2.07
Diluted net income per limited partner unit	$ 1.72	$ 0.05	$ 1.77	$ 2.03	$ 0.03	$ 2.06
Weighted average number of limited partner units used for basic net income per unit calculation	58,716	58,716	58,716	66,361	66,361	66,361
Weighted average number of limited partner units used for diluted net income per unit calculation	58,844	58,844	58,844	66,625	66,625	66,625

Significant pro forma adjustments include revenues and expenses for the period prior to our acquisitions.

The following acquisitions were accounted for as acquisitions of assets:

Pipeline Asset Acquisition. On October 1, 2004, we acquired more than 2,000 miles of petroleum products pipeline system assets from Shell for approximately $488.9 million. In addition to the purchase price, we paid approximately $30.1 million for inventory related to a third-party supply agreement under which we received $14.0 million cash collateral, assumed approximately $57.6 million of existing liabilities and incurred approximately $3.3 million for transaction costs. During June 2004, we paid Shell $24.6 million as earnest money associated with the acquisition, which was applied against the purchase price at closing.

The assets we acquired from Shell had not been operated historically as a separate division or subsidiary. Shell operated these assets as part of its more extensive transportation and terminalling and crude oil and refined products operations. As a result, Shell did not maintain complete and separate financial statements for these assets as an independent business unit. We have made significant changes to the assets, including construction of additional connections between the acquired assets and our existing infrastructure, resulting in significant operating differences and revenues generated. Additionally, differences in our operating approach have resulted in obtaining different revenues and results of operations than those historically achieved by Shell. For these reasons, this acquisition constituted an acquisition of assets, and not of a business.

We integrated most of the assets acquired from Shell into the operations of our petroleum products pipeline system utilizing our existing accounting, financial reporting and measurement and control systems. In order to facilitate this integration, we entered into a transition services agreement with Shell which terminated at the end of February 2005. We also entered into transportation, terminalling and supply agreements with third parties, including Shell, for the refined petroleum products pipelines, terminals and system storage facilities that we acquired. We charge applicable tariffs and fees for transportation and terminalling services with respect to these assets in order to generate revenues and cash for distribution to our general partner and unitholders.

Assumed Liabilities. In conjunction with the acquisition, we agreed to assume from Shell a third-party supply agreement, the terms of which management believed to be significantly below-market rates, and we recognized the $43.5 million fair value of the supply agreement as an increase in the recorded book value of the assets acquired with an offsetting liability.

In 2003, Shell entered into a consent decree with the United States Environmental Protection Agency ("EPA") arising out of a June 1999 incident unrelated to the assets we acquired from Shell. In order to resolve Shell's civil liability for the incident, Shell agreed to pay civil penalties and to comply with certain terms set out in the consent decree. These terms include requirements for testing and maintenance of a number of Shell's pipelines, including two of the pipelines we acquired, the creation of a damage prevention program, submission to independent monitoring and various reporting requirements. The consent decree imposes penalties for non-compliance for a period of at least five years from the date of the consent decree. Under our purchase agreement with Shell, we agreed, at our expense, to complete any remaining remediation work required under the consent decree with respect to the acquired pipelines. We recognized a liability of approximately $8.6 million associated with this agreement. Shell has agreed to retain responsibility under the consent decree for the ongoing independent monitoring obligations.

As part of the acquisition, Shell agreed to retain liabilities and expenses related to active environmental remediation projects, other than those relating to the consent decree discussed above. In addition, Shell agreed to indemnify us for certain environmental liabilities arising from pre-closing conditions so long as we provide notice of those conditions no later than October 1, 2006. Shell's indemnification obligation is subject to a $0.3 million per-claim deductible and a $30.0 million aggregate cap.

We recorded approximately $2.1 million of environmental liabilities related to our estimates for remediation sites that Shell did not consider to be currently active. Also, upon closing of this acquisition, we were assessed a use tax liability of $1.1 million by the State of Oklahoma.

Allocation of Purchase Price. The purchase price allocation of the assets acquired and liabilities assumed from Shell is as follows (in millions):

Purchase price:	
Cash paid for pipeline systems	$488.9
Cash paid for inventory	30.1
Capitalized portion of transaction costs	3.3
Liabilities assumed:	
Fair value of third-party supply agreement	43.5
Consent decree	8.6
Property tax liability	2.3
Environmental	2.1
Use tax liability	1.1
Total liabilities assumed	57.6
Total purchase price	$579.9
Allocation of purchase price:	
Property, plant and equipment	$548.3
Inventory	30.1
Prepaid assets	1.5
Total purchase price	$579.9

Financing. The transactions completed to finance the assets acquired from Shell are discussed in detail in Note 3— Debt and Equity Offerings.

Agreements with Shell. In connection with our acquisition of this refined petroleum products pipeline system, we entered into three-year terminalling and transportation agreements and a five-year storage lease agreement with Shell for a combined minimum revenue commitment averaging approximately $28.1 million per year through September 30, 2007 and approximately $0.8 million per year thereafter through September 30, 2009. Management has concluded that these contracts reflected market prices in effect at the time.

Petroleum Products Pipeline Terminals. In fourth-quarter 2005, we acquired two terminals that are connected to our 8,500-mile petroleum products pipeline system. The terminals include 0.4 million barrels of combined usable storage capacity. The terminals are located in Wichita, Kansas and Aledo, Texas. These terminals were acquired from privately-held companies for cash of approximately $10.9 million, all of which was recorded to property, plant and equipment. The operating results of the Wichita, Kansas and Aledo, Texas terminals have been included in our petroleum products pipeline system segment since their respective acquisition dates.

In conjunction with the acquisition of the Aledo, Texas terminal, we negotiated a partial settlement of the third-party supply agreement we assumed as part of our pipeline system acquisition in October 2004. As a result, we recorded a reduction in the supply agreement liability of $7.6 million.

7. Inventory

Inventories at December 31, 2004 and 2005 were as follows (in thousands):

	December 31, 2004	December 31, 2005
Refined petroleum products	$28,694	$56,680
Natural gas liquids	12,682	19,282
Additives	1,632	1,805
Other	389	388
Total inventories	$43,397	$78,155

The significant increase in refined petroleum products inventories is primarily the impact of significantly higher petroleum prices at December 31, 2005 compared to December 31, 2004.

8. Property, Plant and Equipment

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

	December 31, 2004	December 31, 2005	Estimated Depreciable Lives
Construction work-in-progress	$ 18,162	$ 28,657	
Land and rights-of-way	47,185	51,476	
Carrier property	1,294,500	1,370,793	24 – 50 years
Buildings	10,892	12,264	20 – 53 years
Storage tanks	246,164	285,884	20 – 40 years
Pipeline and station equipment	134,954	100,398	4 – 59 years
Processing equipment	163,229	221,804	3 – 53 years
Other	41,798	44,867	3 – 48 years
Total	$1,956,884	$2,116,143	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes capitalized interest at both December 31, 2004 and 2005 of $19.2 million. Depreciation expense for the years ended December 31, 2003, 2004 and 2005 was $35.3 million, $40.5 million and $54.9 million, respectively.

9. Equity Investments

Effective March 2, 2004, we acquired a 50% ownership in Osage Pipeline for $25.0 million. The remaining 50% interest is owned by NCRA. The 135-mile Osage pipeline transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to the NCRA refinery in McPherson, Kansas and the Frontier refinery in El Dorado, Kansas. Our agreement with NCRA calls for equal sharing of Osage Pipeline's net income. Income from our equity investment in Osage is included with our petroleum products pipeline system segment.

We use the equity method of accounting for this investment. Summarized financial information for Osage Pipeline is presented below (in thousands):

	March 2, 2004 Through December 31, 2004	Year Ended December 31, 2005
Revenue	$9,814	$12,573
Net income	$4,310	$ 7,537

The condensed balance sheet for Osage Pipeline as of December 31, 2004 and 2005 is presented below (in thousands):

	December 31,	
	2004	2005
Current assets	$3,278	$4,767
Noncurrent assets	$5,006	$4,535
Current liabilities	$ 351	$ 431
Members' equity	$7,933	$8,871

A summary of our equity investment in Osage Pipeline is as follows (in thousands):

	March 2, 2004 Through December 31, 2004	Year Ended December 31, 2005
Investment at beginning of period	$25,032	$25,084
Earnings in equity investment:		
Proportionate share of earnings	2,155	3,768
Amortization of excess investment	(553)	(664)
Net earnings in equity investment	1,602	3,104
Cash distributions	(1,550)	(3,300)
Equity investment at end of period	$25,084	$24,888

Our investment in Osage Pipeline included an excess net investment amount of $21.7 million. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. The unamortized excess net investment amount at December 31, 2004 and 2005 was $21.2 million and $20.5 million, respectively.

10. Major Customers and Concentration of Risks

Major Customers. The percentage of revenues derived by customers that accounted for 10% or more of our total revenues is provided in the table below. Customer A is a customer of both our petroleum products pipeline and petroleum products terminals segments. Customer B is a customer of our petroleum products pipeline segment that purchases petroleum products from us pursuant to a supply agreement we assumed in connection with our acquisition of a pipeline system in October 2004. Our credit policies are described in *Trade Receivables and Allowance for Doubtful Accounts* in Note 2—Summary of Significant Accounting Policies. No other customer accounted for more than 10% of our consolidated total revenues during 2003, 2004 or 2005.

	2003	2004	2005
Customer A	27%	19%	9%
Customer B	0%	13%	42%
Total	27%	32%	51%

Concentration of Risks. We transport petroleum products for refiners and marketers in the petroleum industry. The major concentration of our petroleum products pipeline system's revenues is derived from activities conducted in the central United States. Sales to and revenues from our customers are generally unsecured, and the financial condition and creditworthiness of customers are periodically evaluated. We have the ability with many of our pipeline and terminals contracts to sell stored customer products to recover unpaid receivable balances, if necessary. We also require additional security, as considered necessary. For example, credit exposure is mitigated through the use of cash deposits from Customer B and letters of credit from Customer A. Issues impacting the petroleum refining and marketing and ammonia industries could impact our overall exposure to credit risk.

The employees assigned to conduct our operations were employees of MGG through December 24, 2005. On December 24, 2005, MGG transferred all of its employees to its general partner, MGG GP. As of December 31, 2005, MGG GP employed approximately 1,029 employees. MGG GP considers its employee relations to be good.

At December 31, 2005, the labor force of 545 employees assigned to our petroleum products pipeline system is concentrated in the central United States. Approximately 40% of these employees were represented by the United Steel Workers Union and covered by collective bargaining agreements that extend through January 31, 2009. The labor force of 227 employees assigned to our petroleum products terminals operations at December 31, 2005 is primarily concentrated in the southeastern and Gulf Coast regions of the United States. At December 31, 2005, none of the terminal operations employees were represented by labor unions. However, on January 5, 2005 the Teamsters Union filed a petition with the National Labor Relations Board seeking recognition as the exclusive collective bargaining representative for 25 employees at our New Haven, Connecticut terminal. A recognition election was held on February 11, 2005, and the employees voted to not be represented by the Teamsters Union. Our ammonia pipeline is operated by a third-party contractor and no employees are specifically assigned to those operations.

11. Employee Benefit Plans

Williams sold its interest in us to MGG on June 17, 2003. Employees dedicated to or otherwise supporting our operations remained employees of Williams through December 31, 2003 and many participated in Williams sponsored employee benefit plans. For the period from June 18, 2003 through December 31, 2003, Williams charged MGG for the services of the employees in accordance with a services agreement (see *Change of Ownership of General Partner* in Note 1—Organization and Basis of Presentation for a further discussion of this matter) and we reimbursed MGG for those costs.

Williams offered certain of these employees non-contributory defined-benefit plans that provided pension, retiree medical and life insurance benefits. Cash contributions to the plans were made by Williams and were not specifically identifiable to the dedicated employees' participation. Affiliate expense charges from Williams to us related to the dedicated employees' participation in the plans totaled $1.8 million for the period from January 1, 2003 to June 17, 2003. Expense charges from Williams to us under Williams' services agreement with MGG related to the period from June 18, 2003 through December 31, 2003 were not specifically identifiable to the dedicated employees' participation in the plan.

Employees dedicated to or otherwise supporting our operations also participated in a Williams' defined-contribution plan. The plan provided for matching contributions within specified limits. Affiliate charges from Williams to us (through MGG) related to the dedicated employees' participation in the plan totaled $0.7 million for the period from January 1, 2003 to June 17, 2003. Expense charges from Williams to us (through MGG) under the services agreement related to the period from June 18, 2003 through December 31, 2003 are not specifically identifiable to the dedicated employees' participation in the plan.

On January 1, 2004, MGG assumed sponsorship of a union pension plan for certain hourly employees. Additionally, MGG began sponsorship of a pension plan for certain non-union employees, a post-retirement benefit plan for selected employees and a defined contribution plan effective January 1, 2004. The sponsorship of these plans was transferred from MGG to MGG GP on December 24, 2005. We are required to reimburse the plan sponsor for its obligations associated with the pension plans, post-retirement benefit plan and defined contribution plan for qualifying individuals assigned to our operations.

The annual measurement date for the plans is December 31. The following table presents the changes in benefit obligations and plan assets for pension benefits and other post-retirement benefits for the years ended December 31, 2004 and 2005. The table also presents a reconciliation of the funded status of these benefits to the amount recorded in the consolidated balance sheet at December 31, 2004 and 2005 (in thousands):

	Pension Benefits		Other Post-Retirement Benefits	
	2004	2005	2004	2005
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 26,294	$ 33,897	$ 18,266	$ 12,999
Service cost	3,647	4,215	324	530
Interest cost	1,707	1,866	682	994
Plan participants' contributions	—	—	10	39
Actuarial loss	4,044	1,199	1,106	4,834
Other[(a)]	—	—	(7,357)	—
Benefits paid	(1,795)	(2,055)	(32)	(116)
Benefit obligation at end of year	$ 33,897	$ 39,122	12,999	19,280
Change in plan assets:				
Fair value of plan assets at beginning of year	19,453	22,146	—	—
Employer contributions	3,056	4,813	22	77
Plan participants' contributions	—	—	10	39
Actual return on plan assets	1,432	561	—	—
Benefits paid	(1,795)	(2,055)	(32)	(116)
Fair value of plan assets at end of year	22,146	25,465	—	—
Funded status	(11,751)	(13,657)	(12,999)	(19,280)
Unrecognized net actuarial loss	4,249	6,780	1,106	5,366
Unrecognized prior service cost	6,164	5,487	9,111	7,313
Accrued benefit cost	$ (1,338)	$ (1,390)	$ (2,782)	$ (6,601)
Amounts recognized in the statement of financial position:				
Accrued benefit cost	(1,338)	(3,165)	(2,782)	(6,601)
Intangible assets	—	1,432	—	—
Accumulated other comprehensive income	—	343	—	—
Net amount recognized	$ (1,338)	$ (1,390)	$ (2,782)	$ (6,601)
Accumulated benefit obligation	$ 23,441	$ 28,629	N/A	N/A

(a) The post-retirement medical plan pays eligible claims secondary to Medicare. As a result of the Prescription Drug Act of 2003, prescription claims cost decreased which resulted in a decrease in the post-retirement benefit obligation described as "Other" in the table above.

The amounts included in the pension benefits in the above table combine the union pension plan with the non-union pension plan. At December 31, 2004, the union pension plan had an accumulated benefit obligation of $21.9 million, which exceeded the fair value of plan assets of $20.2 million. At December 31, 2005 the accumulated benefit obligations of both plans exceeded the fair value of their respective plan assets.

Net pension and other post-retirement benefit expense for the year ended December 31, 2004 and 2005 consists of the following (in thousands):

	Pension Benefits		Other Post-Retirement Benefits	
	2004	2005	2004	2005
Components of net periodic pension and post-retirement benefit expense:				
Service cost	$ 3,647	$ 4,215	$ 324	$ 530
Interest cost	1,707	1,866	682	994
Expected return on plan assets	(1,637)	(1,918)	—	—
Amortization of prior service cost	677	677	1,798	1,798
Amortization of actuarial loss	—	25	—	575
Net periodic expense	$ 4,394	$ 4,865	$2,804	$3,897

The weighted-average assumptions utilized to determine benefit obligations as of December 31, 2004 and 2005 are as follows:

	Pension Benefits		Other Post-Retirement Benefits	
	2004	2005	2004	2005
Discount rate	5.75%	5.50%	5.75%	5.50%
Rate of compensation increase	5.00%	5.00%	N/A	N/A

The weighted-average assumptions utilized to determine net pension and other post-retirement benefit expense for the years ended December 31, 2004 and 2005 are as follows:

	Pension Benefits		Other Post-Retirement Benefits	
	2004	2005	2004	2005
Discount rate	6.25%	5.75%	6.25%	5.75%
Expected return on plan assets	8.50%	8.50%	N/A	N/A
Rate of compensation increase	5.00%	5.00%	N/A	N/A

The non-pension post-retirement 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 our 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 2006 is 10.3% and systematically decreases to 5% by 2014. The health care cost trend rate assumption has a significant effect on the amounts reported. A 1.0% change in assumed health care cost trend rates would have the following effect (in thousands):

	Point Increase	Point Decrease
Change in total of service and interest cost components	$ 235	$ 219
Change in post-retirement benefit obligation	2,845	2,655

The expected long-term rate of return on plan assets was determined by combining a review of historical returns of portfolios with assets similar to the current portfolios of the union and non-union pension plans, projected returns and target weightings of each asset classification. Our investment objectives for the assets within the pension plans are to obtain a balance between long-term growth of capital and generation of income to meet withdrawal requirements, 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. Our tolerance for risk is analyzed based on the impact on the predictability of contribution requirements, probability of under funding, risk-adjusted returns and investment return volatility. Funds are invested through the use of multiple investment managers. Our target allocation percentages and the actual weighted-average asset allocation at December 31, 2005 are as follows:

	Actual	Target
Equity securities	65%	65%
Debt securities	31%	34%
Other	4%	1%

Benefits expected to be paid through December 31, 2015 are as follows (in thousands):

	Pension Benefits	Other Post-retirement Benefits
2006	$ 829	$ 109
2007	873	244
2008	937	404
2009	966	589
2010	1,115	785
2011 through 2015	7,269	6,349

Contributions estimated to be paid in 2006 are $5.6 million and $0.1 million for the pension and other post-retirement benefit plans, respectively. We incurred costs related to the defined contribution plan during 2004 and 2005 of $3.1 million and $3.8 million, respectively.

12. Related Party Transactions

Affiliate Entity Transactions. In March 2004, we acquired a 50% ownership interest in Osage Pipeline. In April 2004, we began operating the Osage pipeline, for which we are paid a fee. During 2004 and 2005, we received operating fees from Osage Pipeline of $0.5 million and $0.7 million, respectively, which we reported as affiliate management fee revenues. In 2004, we also received $0.3 million from Osage Pipeline for fees to transition accounting, billing and other administrative functions to us. We recorded these fees as other income, which is netted into operating expenses in our results of operations.

On June 17, 2003, Williams sold its ownership interests in us to MGG. Costs and expenses related to activities between Williams and its affiliates and us after June 17, 2003, have been accounted for as unaffiliated third-party transactions. Transactions after June 17, 2003 between us and MGG and its affiliates have been accounted for as affiliate transactions. The following table summarizes expenses from various affiliate companies with us which are reflected as expenses in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2003	2004	2005
Affiliates of Williams—allocated G&A expenses	$23,880	$ —	$ —
Affiliates of Williams—allocated operating expenses	68,079	—	—
Affiliates of Williams—product purchases	472	—	—
MGG—allocated operating expenses	98,804	58,777	65,360
MGG—allocated G&A expenses	32,966	54,466	60,261
MGG GP—allocated operating expenses	—	—	1,551
MGG GP—allocated G&A expenses	—	—	870

In June 2003, we and our general partner entered into a services agreement with MGG pursuant to which MGG agreed to provide the employees necessary to conduct our operations. For the period June 18, 2003 (the date MGG acquired Williams' ownership interest in us) through December 31, 2003, all of the personnel assigned to us remained employees of Williams. On June 18, 2003, MGG entered into a transition services agreement whereby Williams agreed to provide all of our operating and G&A functions through December 31, 2003. MGG allocated all costs it incurred with Williams under this transition services agreement to us and we reimbursed MGG for these costs, subject to our G&A expense reimbursement agreement with MGG. We reimbursed MGG for all payroll and benefit costs it incurred from January 1, 2004 through December 24, 2005, subject to our G&A expense reimbursement agreement. On December 24, 2005, the employees necessary to conduct our operations were transferred to MGG's general partner, the services agreement with MGG was terminated and a new services agreement with MGG's general partner was executed. Consequently, we now reimburse MGG's general partner for the costs of employees necessary to conduct our operations. Additionally, in June 2003, MGG agreed to reimburse us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap as defined in the omnibus agreement. The amount of G&A costs that that was required to be reimbursed by MGG to us was $6.4 million and $3.3 million in 2004 and 2005, respectively. The additional G&A costs incurred but not reimbursed by MGG are discussed below under *Reimbursement of G&A Expenses.* We settle our affiliate payroll and payroll-related expenses and post-retirement benefit costs with MGG's general partner on a monthly basis. We settle our long-term pension liabilities through annual contributions to MGG's general partner's pension fund.

For the period January 1, 2003 through June 17, 2003, Williams allocated operating expenses to our general partner, which included all operating costs directly associated with our operations. Additionally, Williams allocated to us both direct and indirect G&A expenses, which were subject to an expense limitation.

Williams and certain of its affiliates had indemnified us against certain environmental costs. The environmental indemnifications we had with Williams were settled during 2004. In addition, in June 2003, MGG agreed to assume from Williams certain indemnified obligations to us. See Note 18—Commitments and Contingencies for information relative to these items.

Reimbursement of G&A Expense. We pay MGG and MGG GP for direct and indirect G&A expenses incurred on our behalf. MGG, in turn, reimburses us for expenses in excess of a G&A cap as described below:

- The reimbursement obligation is subject to a lower cap amount, which is calculated as follows:
  - For the period June 18, 2003 through December 31, 2003, MGG reimbursed us $6.0 million for G&A costs in excess of a lower cap amount;
  - For each succeeding fiscal year, the lower cap is adjusted by the greater of: (i) 7%, or (ii) the percentage increase in the Consumer Price Index—All Urban Consumers, U.S. City Average, Not Seasonally Adjusted. However, the reimbursement amount is also adjusted for acquisitions, construction projects, capital improvements, replacements or expansions that we complete that are expected to increase our G&A costs. During 2004, MGG reimbursed us $6.4 million for G&A costs in excess of the lower cap amount of $41.8 million and in 2005 MGG reimbursed us $3.3 million in excess of a lower cap amount of $49.3 million;
  - Additionally, the expense reimbursement limitation excludes: (i) expenses associated with equity-based incentive compensation plans and (ii) implementation costs associated with changing our name and expenses and capital expenditures associated with transitioning the assets, operations and employees from Williams to MGG or us.
- The reimbursement limitation is further subject to an upper cap amount. MGG is not required to reimburse us for any G&A expenses that exceed this upper cap amount. The upper cap is calculated as follows:
  - For the period of June 18, 2003 through December 31, 2003, the upper cap was approximately $26.6 million, which represents an annual upper cap amount of $49.3 million pro-rated for the period from June 18, 2003 through December 31, 2003; and
  - For each succeeding fiscal year, the upper cap is increased annually by the lesser of: (i) 2.5%, or (ii) the percentage increase in the Consumer Price Index—All Urban Consumers, U.S. City Average, Not Seasonally Adjusted. The upper cap will also be adjusted for acquisitions, construction projects and capital improvements, replacements or expansions that we complete that are expected to increase our G&A costs. For 2004 and 2005, the upper cap was adjusted to $51.5 million and $57.6 million, respectively. Our G&A expenses have not exceeded the upper cap since this agreement was executed.

Other Related Party Transactions. MGG, which owns our general partner, is partially owned by an affiliate of the Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). Two of the members of our general partner's eight member board of directors are nominees of CRF. On January 25, 2005, CRF, through affiliates, acquired an interest in the general partner of SemGroup, L.P. ("SemGroup") and limited partner interests in SemGroup. CRF's total combined general and limited partner interest in SemGroup is approximately 30%. One of the members of SemGroup's general partner's seven-member board of directors is a nominee of CRF, with three votes on such board. We, through our affiliates, are a party to a number of transactions with SemGroup and its affiliates, details of which are provided in the following table (in millions):

	Year Ended December 31, 2005
Sales of petroleum products	$144.8
Purchases of petroleum products	90.0
Terminalling and other services revenues	5.9
Storage tank lease revenues	2.8
Storage tank lease expense	1.0

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2005, we had recognized a receivable of $6.2 million from and a payable of $6.1 million to SemGroup and its affiliates. The receivable is included with the trade accounts receivable amounts and the payable is included with the accounts payable amounts on our consolidated balance sheets.

CRF also has an ownership interest in the general partner of Buckeye Partners, L.P. ("Buckeye"). In 2005, we incurred $0.3 million of operating expenses with Norco Pipe Line Company, LLC, which is a subsidiary of Buckeye.

The board of directors of our general partner has adopted a Board of Directors Conflict of Interest Policy and Procedures. In compliance with this policy, CRF has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to SemGroup and Buckeye. As part of these procedures, none of the nominees of CRF will serve on our general partner's board of directors and on SemGroup's or Buckeye's general partner's board of directors at the same time.

During May 2005, our general partner's board of directors appointed John P. DesBarres as an independent board member. Mr. DesBarres currently serves as a board member for American Electric Power Company, Inc. As of December 31, 2005, our operating expenses totaled $1.7 million of principally power costs that we incurred with Public Service Company of Oklahoma, which is a subsidiary of American Electric Power Company, Inc.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives increasing percentages of our total distributions. Distributions to our general partner above the highest target level are at 50%. As the owner of our general partner, MGG indirectly benefits from these distributions. Through ownership of the Class B common units of MGG Midstream Holdings, L.P., which, at December 31, 2005, was 6% of the total ownership of MGG, certain executive officers of our general partner also indirectly benefit from these distributions. In 2004 and 2005, distributions paid to our general partner totaled $16.7 million and $30.1 million, respectively. In addition, during 2004 and 2005, MGG received distributions totaling $28.7 million and $5.0 million, respectively, related to the common and subordinated units it owned at the time. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.5525 per unit, our general partner would receive distributions of approximately $51.4 million in 2006 on its combined 2% general partner interest and incentive distribution rights.

During February 2006, MGG sold 35% of its MGG common units in an initial public offering. We did not receive any of the proceeds from MGG's initial public offering and do not expect our ownership structure or operations to be materially impacted by this transaction. In connection with the closing of this offering, we amended our partnership agreement to remove the requirement for our general partner to maintain its 2% interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

13. Debt

Our debt at December 31, 2004 and 2005 was as follows (in thousands):

	December 31, 2004	December 31, 2005
Magellan Pipeline notes:		
Current portion	$ 15,100	$ 14,345
Long-term portion	289,574	270,074
Total Magellan Pipeline notes	304,674	284,419
6.45% Notes due 2014	250,292	249,546
5.65% Notes due 2016	249,702	250,019
Revolving credit facility	—	13,000
Total debt	$804,668	$796,984

We had $799.9 million of debt outstanding as of December 31, 2005, excluding discounts incurred on debt issuances and market value adjustments to long-term debt associated with qualifying hedges, with maturities as follows: $14.3 million—2006; $272.6 million—2007; $0—2008; $13.0 million—2009; and $500.0 million thereafter.

6.45% Notes due 2014. On May 25, 2004, we sold $250.0 million aggregate principal of 6.45% notes due June 1, 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million, and this discount is being accreted over the life of the notes. Including the impact of the amortization of the realized gains on the interest hedges associated with these notes (see Note 14—Derivative Financial Instruments), the effective interest rate of these notes as of December 31, 2005 was 6.3%. Interest is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2004.

5.65% Notes due 2016. On October 7, 2004, we issued $250.0 million of senior notes due 2016. The notes were issued for the discounted price of 99.9%, or $249.7 million, and this discount is being accreted over the life of the notes. Including the impact of hedges associated with these notes (see Note 14—Derivative Financial Instruments), the weighted-average interest rate of these notes at December 31, 2005 was 5.6%. Interest is payable semi-annually in arrears on April 15 and October 15 of each year, beginning April 15, 2005.

The indenture under which the 6.45% and 5.65% notes were issued does not limit our ability to incur additional unsecured debt. The indenture contains covenants limiting, among other things, our ability to incur indebtedness secured by certain liens, engage in certain sale-leaseback transactions, and consolidate, merge or dispose of all or substantially all of our assets. We are in compliance with these covenants.

May 2004 Revolving Credit Facility. In connection with our May 2004 refinancing, we entered into a five-year $125.0 million revolving credit facility with a syndicate of banks. In September 2004, we increased the facility to $175.0 million. Borrowings under this revolving credit facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.6% to 1.5% based on our credit ratings. As of December 31, 2005, $13.0 million was outstanding under this facility, and $1.1 million of the facility was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets. The weighted-average interest rate on the revolver at December 31, 2005 was 5.1%. Interest is also assessed on the unused portion of the credit facility at a rate from 0.15% to 0.35% depending on our credit rating.

The revolving credit facility requires us to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 4.50 to 1.00; and (ii) consolidated EBITDA to interest expense of at least 2.50 to 1.00. In addition, the revolving credit facility contains covenants that limit our ability to, among other things, incur additional indebtedness or modify our other debt instruments, encumber our assets, make debt or equity investments, make loans or advances, engage in certain transactions with affiliates, engage in sale and leaseback transactions, merge, consolidate, liquidate or dissolve, sell or lease all or substantially all of our assets and change the nature of our business. We are in compliance with these covenants.

Magellan Pipeline Notes. During October 2002, Magellan Pipeline entered into a private placement debt agreement with a group of financial institutions for $480.0 million of fixed rate Senior Secured Notes. These notes were secured with our membership interest in and assets of Magellan Pipeline until our refinancing plan was executed in May 2004 (see Note 3–Debt and Equity Offerings). As part of that refinancing, we repaid all of the $178.0 million Series A notes and the fixed rate Series B noteholders released the collateral which secured those notes, except for cash deposited in an escrow account in anticipation of semi-annual interest payments on the Magellan Pipeline notes. The maturity date of the senior notes is October 7, 2007. However, on October 7, 2005 we repaid 5.0%, or $15.1 million, of the principal outstanding, and on October 7, 2006, we will be required to repay 5.0% of the principal amount outstanding on that date. The outstanding principal amount of these senior notes at December 31, 2004 and 2005 was $302.0 million and $286.9 million, respectively; however, the outstanding principal amount of the notes at December 31, 2004 was increased by $2.7 million and at December 31, 2005 was deceased by $2.5 million for the change in the fair value of the associated hedge (see Note 14–Derivative Financial Instruments). The interest rate of the senior notes is fixed at 7.7%. However, including the impact of the associated fair value hedge, which effectively swaps $250.0 million of the notes to floating-rate debt, the weighted-average interest rate for the notes was 8.1% at December 31, 2005.

Deposits for interest due the lenders are made to a cash escrow account and were reflected as restricted cash on our consolidated balance sheets of $5.8 million and $5.5 million at December 31, 2004 and 2005, respectively.

The note purchase agreement, as amended in connection with our May 2004 refinancing, requires Magellan Pipeline to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 3.50 to 1.00, and (ii) consolidated EBITDA to interest expense of at least 3.25 to 1.00. It also requires us to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 4.50 to 1.00, and (ii) consolidated EBITDA to interest expense of at least 2.50 to 1.00. In addition, the note purchase agreement contains additional covenants that limit Magellan Pipeline's ability to incur additional indebtedness, encumber its assets, make debt or equity investments, make loans or advances, engage in certain transactions with affiliates, merge, consolidate, liquidate or dissolve, sell or lease a material portion of its assets, engage in sale and leaseback transactions and change the nature of its business. We are in compliance with these covenants.

During the years ending December 31, 2003, 2004 and 2005, total cash payments for interest on all indebtedness, net of amounts capitalized, were $32.4 million, $35.8 million and $54.0 million, respectively.

14. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. The following table summarizes hedges we have settled associated with various debt offerings (dollars in millions):

Hedge	Date	Gain/(Loss)	Amortization Period
Interest rate hedge	October 2002	$(1.0)	5-year life of Magellan Pipeline notes
Interest rate swaps and treasury lock	May 2004	5.1	10-year life of 6.45% notes
Interest rate swaps	October 2004	(6.3)	12-year life of 5.65% notes

In May 2004, we unwound certain interest rate swap agreements and treasury lock transactions and realized a combined gain of $6.1 million on those transactions. Because the combined notional amounts of the interest rate swap agreements and treasury locks exceeded the total amount of debt issued, a portion of the treasury lock hedge was ineffective. As such, the portion of the realized gain associated with the ineffective portion of the treasury lock hedge, or $1.0 million, was recorded as a gain on derivative during May 2004.

In addition to the above, we have entered into the following interest rate swap agreements:

- During May 2004, we entered into certain interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline senior notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the interest rate swap agreements, we receive 7.7% (the weighted-average interest rate of the outstanding Magellan Pipeline senior notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007, the maturity date of the Magellan Pipeline senior notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period we record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense associated with this hedge of $0.6 million. The fair value of the instruments associated with this hedge at December 31, 2004 and 2005 was $2.7 million and $(2.5) million, respectively, which was recorded to other noncurrent assets and long-term debt at December 31, 2004 and noncurrent liabilities and long-term debt at December 31, 2005.
- 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 which were issued in October 2004. The notional amount of this agreement is $100.0 million and effectively converts $100.0 million of our 5.65% fixed-rate senior notes issued in October 2004 to floating-rate debt. Under the terms of the agreement, we receive the 5.65% fixed rate of the notes and pay LIBOR plus 0.6%. The agreement began on October 15, 2004 and terminates on October 15, 2016, which is the maturity date of these senior notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period we will record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense of $0.3 million associated with this hedge. The fair value of this hedge at December 31, 2004 and December 31, 2005, was $0.8 million and $0.3 million, respectively, which was recorded to other noncurrent assets and long-term debt.

15. Leases

Leases—Lessee

We lease land, office buildings, tanks and terminal equipment at various locations to conduct our 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. Total rent expense was $3.9 million, $4.7 million and $6.3 million in 2003, 2004 and 2005, respectively. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2005, are as follows (in thousands):

2006	$ 2,776
2007	2,708
2008	2,059
2009	1,448
2010	1,443
Thereafter	10,554
Total	$20,988

Leases—Lessor

We have entered into capacity and storage leases with remaining terms from one to 11 years that we account for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum lease payments receivable under operating-type leasing arrangements as of December 31, 2005, are as follows (in thousands):

2006	$ 39,175
2007	28,580
2008	22,002
2009	15,904
2010	9,697
Thereafter	16,645
Total	$132,003

On December 31, 2001, we purchased an 8.5-mile, 8-inch natural gas liquids pipeline in northeastern Illinois from Aux Sable Liquid Products L.P. ("Aux Sable") for $8.9 million. We then entered into a long-term lease arrangement under which Aux Sable is the sole lessee of these assets. We have accounted for this transaction as a direct financing lease. The lease expires in December 2016 and has a purchase option after the first year. Aux Sable has the right to re-acquire the pipeline at the end of the lease for a de minimis amount.

Future minimum lease payments receivable under this direct-financing-type leasing arrangement as of December 31, 2005 were $1.3 million in 2006, $1.3 million in 2007, $1.3 million in 2008, $1.3 million in 2009, $1.3 million in 2010 and $7.5 million cumulatively for all periods after 2010. The net investment under direct financing leasing arrangements as of December 31, 2004 and 2005, were as follows (in thousands):

	December 31,	
	2004	2005
Total minimum lease payments receivable	$15,351	$13,965
Less: Unearned income	7,245	6,283
Recorded net investment in direct financing leases	$ 8,106	$ 7,682

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

	December 31, 2004	December 31, 2005
Classification of direct financing leases:		
Current accounts receivable	$ 423	$ 358
Noncurrent accounts receivable	7,683	7,324
Total	$8,106	$7,682

16. Long-Term Incentive Plan

We have a long-term incentive plan for certain employees who perform services for us and directors of our general partner. The long-term incentive plan consists of two components: phantom units and unit options. The long-term incentive plan permits the grant of awards covering an aggregate of 1.4 million common units. The compensation committee of our general partner's board of directors administers the long-term incentive plan.

In February 2003, our general partner granted 105,650 phantom units pursuant to the long-term incentive plan. These units vested on December 31, 2005. Because we exceeded certain performance metrics, the actual number of units awarded with this grant totaled 180,602 units. The value of these units on December 31, 2005 was $5.8 million.

Following the change in control of our general partner in June 2003, the board of directors of our general partner made the following grants under the long-term incentive plan to certain employees who became dedicated to providing services to us:

- In October 2003, our general partner granted 21,280 phantom units. Of these awards, 9,700 units vested on December 31, 2003, 940 units vested on July 31, 2004, 9,700 units vested on December 31, 2004 and 940 units vested on July 31, 2005.
- On January 2, 2004, our general partner granted 21,712 phantom units. Of these awards, 10,866 units vested on July 31, 2004 and 10,846 units vested on July 31, 2005.

In February 2004, our general partner granted 159,025 phantom units pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant are based on the attainment of short-term and long-term performance metrics. The number of phantom units that could ultimately be issued under this award range from zero units up to a total of 318,048 units; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 40%. The unit awards will vest at the end of 2006. These unit awards are subject to forfeiture if employment is terminated prior to the vesting date. These awards do not have an early vesting feature except where there is a change in control of our general partner. During 2004, we increased our estimate of the number of units that will be awarded under this grant to 289,626 and during 2005 we further increased our estimate to 307,721 units based on the expected attainment of the short-term performance metrics and the probability of attaining higher-than-standard on the long-term performance metrics. The value of the 307,721 unit awards on December 31, 2005 was $9.9 million.

In February 2005, our general partner granted 160,640 phantom units pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant are based on the attainment of long-term performance metrics. The number of phantom units that could ultimately be issued under this award range from zero units up to a total of 321,280 units; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 20%. The unit awards will vest at the end of 2007. Units awards associated with employees who terminate their employment due to death, disability or retirement will be prorated for the period during the vesting period prior to the employee's termination. These awards do not have an early vesting feature except where there is a change in control of our general partner. During 2005, we increased our estimate of the number of units that will be awarded under this grant to 287,532 units based on the probability of attaining higher-than-standard on the long-term performance metrics. The value of the 287,532 unit awards on December 31, 2005 was $9.3 million.

To facilitate the distribution of common units to participants in our long-term incentive plan, our general partner made purchases of our equity securities during 2003, 2004 and 2005 as follows:

Date Units Acquired	Total Number of Units Purchased	Average Price Paid Per Unit
01/09/03	11,106	$17.16
03/01/03	2,464	17.58
06/12/03	12,340	23.68
06/13/03	1,984	23.71
06/19/03	28,800	22.84
08/03/04	7,540	27.00
01/03/05	6,228	28.27
08/01/05	7,557	34.93
Total[(a)]	78,019	

(a) The units purchased to settle awards do not include amounts withheld for income tax withholdings. Additionally, certain awards which vested during 2003, 2004 and 2005 were settled with cash.

The equity-based incentive compensation expense we recognized for 2003, 2004 and 2005 is summarized as follows (in thousands):

	2003	2004	2005
2001 awards	$3,373	$ —	$ —
2002 awards	1,955	—	—
2003 awards	1,740	2,232	2,433
October 2003 awards	309	199	7
January 2004 awards	—	500	102
2004 awards	—	2,809	3,835
2005 awards	—	—	3,134
Total	$7,377	$5,740	$9,511

17. Segment Disclosures

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

On June 17, 2003, Williams sold its interest in us to MGG. Prior to June 17, 2003, affiliate revenues from Williams were accounted for as if the sales were to unaffiliated third parties. Also, prior to June 17, 2003, affiliate G&A costs, other than equity-based incentive compensation, were based on the expense limitations provided for in the omnibus agreement and were allocated to the business segments based on their proportional percentage of revenues. After June 17, 2003, affiliate G&A costs have generally been allocated to the business segments based on a three-factor formula, which considers total salaries, property, plant and equipment and total revenues less product purchases.

The non-GAAP measure of operating margin (in the aggregate and by segment) is presented in the following table. We compute the components of operating margin by 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. We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and G&A expenses, which management does not consider when evaluating the core profitability of an operation.

	Year Ended December 31, 2003				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues:					
Third party	$268,245	$ 78,873	$12,608	$ —	$ 359,726
Affiliate	13,122	—	—	—	13,122
Product sales revenues:					
Third party	106,843	4,679	—	—	111,522
Affiliate	790	—	—	—	790
Total revenues	389,000	83,552	12,608	—	485,160
Operating expenses	126,246	34,677	4,562	(873)	164,612
Environmental	13,256	389	444	—	14,089
Environmental reimbursements	(10,967)	(359)	(492)	—	(11,818)
Product purchases	97,971	1,936	—	—	99,907
Operating margin	162,494	46,909	8,094	873	218,370
Depreciation and amortization	22,320	11,804	1,084	873	36,081
Affiliate G&A expenses	39,214	15,179	2,453	—	56,846
Segment profit	$100,960	$ 19,926	$ 4,557	$ —	$ 125,443
Segment assets	$670,229	$359,927	$28,936	$ —	$1,059,092
Corporate assets					135,532
Total assets					$1,194,624
Goodwill	$ —	$ 22,057	$ —	$ —	$ 22,057
Additions to long-lived assets	$ 12,698	$ 12,383	$ 315	$ —	$ 25,396

During 2003, we recorded a $5.5 million liability for paid-time off benefits associated with the employees supporting us. These costs, charged to 2003 operating and affiliate G&A expenses, resulted from MGG's acquisition of us and our subsequent commitment to reimburse MGG for employee-related liabilities. These costs were charged to our business segments as follows (in millions):

	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Total
Operating expense	$2.6	$0.8	$—	$3.4
Affiliate G&A expense	1.5	0.5	0.1	2.1
Total	$4.1	$1.3	$ 0.1	$5.5

Also, as a result of Williams' sale of its ownership interests in us to MGG, we were responsible for $5.9 million of costs to separate from Williams. Of these costs, $3.7 million was charged to affiliate G&A expense and was allocated to the business units as follows: $2.7 million to petroleum products pipeline, $0.9 million to petroleum products terminals and $0.1 million to the ammonia pipeline system.

	Year Ended December 31, 2004				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 315,044	$ 91,302	$13,922	$(1,151)	$ 419,117
Product sales revenues	264,950	10,819	—	—	275,769
Affiliate management fee revenue	488	—	—	—	488
Total revenues	580,482	102,121	13,922	(1,151)	695,374
Operating expenses	139,082	36,864	5,300	(4,180)	177,066
Environmental	38,744	3,039	2,206	—	43,989
Environmental reimbursements	(37,647)	(2,839)	(912)	—	(41,398)
Product purchases	249,064	6,535	—	—	255,599
Equity earnings	(1,602)	—	—	—	(1,602)
Operating margin	192,841	58,522	7,328	3,029	261,720
Depreciation and amortization	24,970	13,375	471	3,029	41,845
Affiliate G&A expenses	38,335	13,781	2,350	—	54,466
Segment profit	$ 129,536	$ 31,366	$ 4,507	$ —	$ 165,409
Segment assets	$1,246,083	$398,220	$24,590	$ —	$1,668,893
Corporate assets					148,939
Total assets					$1,817,832
Goodwill	$ —	$ 22,007	$ —	$ —	$ 22,007
Additions to long-lived assets	$ 547,868	$ 53,659	$ 521	$ —	$ 602,048

In October 2004, we acquired certain pipeline and terminal assets (see Note 6—Acquisitions), which significantly affected the revenue and expense categories above for the petroleum products pipeline system during the fourth quarter of 2004.

	Year Ended December 31, 2005				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 381,926	$105,563	$15,849	$(3,142)	$ 500,196
Product sales revenues	625,725	11,444	—	(960)	636,209
Affiliate management fee revenue	667	—	—	—	667
Total revenues	1,008,318	117,007	15,849	(4,102)	1,137,072
Operating expenses	176,781	40,197	6,849	(6,039)	217,788
Environmental	8,590	2,102	1,315	—	12,007
Product purchases	578,806	5,294	—	(1,469)	582,631
Equity earnings	(3,104)	—	—	—	(3,104)
Operating margin	247,245	69,414	7,685	3,406	327,750
Depreciation and amortization	36,291	15,861	749	3,406	56,307
Affiliate G&A expenses	44,597	14,399	2,135	—	61,131
Segment profit	$ 166,357	$ 39,154	$ 4,801	$ —	$ 210,312
Segment assets	$1,274,795	$510,162	$30,787	$ —	$1,815,744
Corporate assets					60,774
Total assets					$1,876,518
Goodwill	$ —	$ 24,430	$ —	$ —	$ 24,430
Additions to long-lived assets	$ 29,701	$122,815	$ 564	$ —	$ 153,080

18. Commitments and Contingencies

Estimated liabilities for environmental costs were $60.8 million and $58.2 million at December 31, 2004 and 2005, respectively. These estimates are provided on an undiscounted basis and have been classified as current or non-current based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years. Our environmental liabilities include accruals associated with the *EPA Issue* and *Kansas City, Kansas Release*, as follows:

EPA Issue. In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to Williams based on a preliminary determination that Williams may have systematic problems with petroleum discharges from pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. This matter was included in the indemnification settlement with Williams (see *Environmental Indemnification Settlement* discussion below). We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

Kansas City, Kansas Release. During the second quarter of 2005, we experienced a line break and release of approximately 2,900 barrels of product on our petroleum products pipeline near our Kansas City, Kansas terminal. As of December 31, 2005, we have estimated the costs associated with this release of approximately $2.7 million. We have spent $1.7 million on remediation associated with this release and have $1.0 million of environmental liabilities recorded at December 31, 2005. We have not been assessed a penalty by the EPA, or any other regulatory agency, relative to this release and we are unable to estimate with any certainty what penalties, if any, might be assessed. Therefore, our environmental accrual for this matter, as of December 31, 2005, includes no amounts for penalties. If penalties are assessed, the recognition of such obligations, which could occur in the near term, could be material to our results of operations and cash flows.

Environmental Indemnification Settlement. Prior to May 27, 2004, Williams had agreed to indemnify us against certain environmental losses, among other things, associated with assets that Williams contributed to us at the time of our initial public offering or which we subsequently acquired from Williams. In May 2004, we and our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from these indemnifications. Under this agreement, we received $35.0 million and $27.5 million from Williams on July 1, 2004 and 2005, respectively, and expect to receive installment payments from Williams of $20.0 million and $35.0 million on July 1, 2006 and 2007, respectively.

While the settlement agreement releases Williams from its environmental and certain indemnifications, other indemnifications remain in effect. These remaining indemnifications cover:

- Issues involving employee benefits matters;
- Issues involving rights-of-way, easements and real property, including asset titles; and
- Unlimited losses and damages related to tax liabilities.

As of December 31, 2004 and December 31, 2005, known liabilities that would have been covered by Williams' previous indemnity agreements were $40.8 million and $43.1 million, respectively. Through December 31, 2005, we have spent $17.4 million of the $117.5 million indemnification settlement amount for indemnified matters, including $6.6 million of capital costs. The cash we have received from the indemnity settlement is not reserved and has been used by us for our various other cash needs, including expansion capital spending.

MGG Indemnification Obligation. As part of its negotiations with Williams for the June 2003 acquisition of Williams' interest in us, MGG assumed Williams' obligations for $21.9 million of our known environmental liabilities. To the extent the environmental and other Williams indemnity claims against MGG are less than $21.9 million, MGG will pay to Williams the remaining difference between $21.9 million and the indemnity claims paid by MGG. Recorded liabilities associated with this indemnification were $10.4 million and $5.5 million at December 31, 2004 and December 31, 2005, respectively.

Environmental Receivables. Upon MGG's assumption of Williams' environmental obligations to us, as discussed in *MGG Indemnification Obligation* above, we recorded a receivable from MGG for $21.9 million.

Our receivable balance with MGG associated with this environmental obligation at December 31, 2004 and 2005 was $11.5 million and $6.7 million, respectively. Environmental receivables from insurance carriers at December 31, 2004 and 2005 were $7.4 million and $2.1 million, respectively. We invoice MGG and third-party insurance companies for reimbursement as environmental remediation work is performed.

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, we do not expect the ultimate resolution of all claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements to have a material adverse effect on our future financial position, results of operations or cash flows.

19. Quarterly Financial Data (unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2004				
Revenues	$133,144	$142,220	$158,500	$261,510
Operating margin	56,975	66,861	62,628	75,256
Total costs and expenses	98,698	98,836	119,986	214,047
Net income	25,815	18,457	30,603	35,328
Basic net income per limited partner unit	0.44	0.31	0.48	0.48
Diluted net income per limited partner unit	0.44	0.31	0.48	0.48
2005				
Revenues	$258,333	$255,586	$313,943	$309,210
Operating margin	82,085	80,470	84,031	81,164
Total costs and expenses	204,862	204,985	261,103	258,914
Net income	42,123	38,968	40,758	37,634
Basic net income per limited partner unit	0.54	0.48	0.56	0.46
Diluted net income per limited partner unit	0.54	0.48	0.56	0.46

All 2004 quarters were impacted by the results from our acquisition of 14 terminals in January 2004 and our equity investment in Osage Pipeline in March 2004. Second-quarter 2004 results were impacted by $16.7 million of net refinancing costs, which included $12.7 million of debt prepayment premiums associated with the early extinguishment of a portion of our previously outstanding Magellan Pipeline senior notes, a $5.0 million write-off of unamortized debt placement costs associated with the retired debt and a $1.0 million gain on an interest rate hedge related to the debt refinancing. Fourth-quarter 2004 results were impacted by our pipeline system acquisition, including debt and equity financing transactions (see Note 6—Acquisitions).

Third-quarter and fourth-quarter 2005 revenues were impacted by high and increasing gasoline prices on our petroleum products blending and fractionation operations and the third-party supply agreement we assumed as part of the pipeline system acquisition in fourth-quarter 2004.

20. 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 the balance sheet approximate fair value due to the short-term maturity or variable rates of these instruments.

Marketable securities: The carrying amounts reported in the balance sheet approximate fair value due to the variable rates of these instruments.

Long-term affiliate receivables: Fair value is determined by discounting estimated cash flows at our incremental borrowing rates.

Long-term receivables: Generally, fair value is determined by discounting estimated future cash flows by the rates inherent in the long-term instruments plus/minus the change in the risk-free rate since inception of the instrument.

Debt: The fair value of traded notes was based on the prices of those notes at December 31, 2004 and 2005. The fair value of our fixed-rate debt at December 3, 2004 and 2005 was determined by discounting estimated future cash flows using our incremental borrowing rate. The fair value of our private placement debt at December 3, 2004 and 2005 was determined by discounting estimated future cash flows using our incremental borrowing rate. The carrying amount of floating-rate borrowings at December 31, 2005 approximates fair value due to the variable rates of those instruments.

Interest rate swaps: Fair value is determined based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been settled at year-end.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2004 and 2005 (in thousands):

	December 31, 2004		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 29,833	$ 29,833	$ 36,489	$ 36,489
Restricted cash	5,847	5,847	5,537	5,537
Marketable securities	87,802	87,802	—	—
Long-term affiliate receivables	4,599	4,035	1,245	1,087
Long-term receivables	8,070	7,159	7,327	6,311
Debt	802,000	845,248	799,900	815,400
Interest rate swaps	3,459	3,459	(2,183)	(2,183)

21. Distributions

We paid the following distributions during 2003, 2004 and 2005 (in thousands, except per unit amounts):

Date Cash Distribution Paid	Per Unit Cash Distribution Amount	Common Units	Subordinated Units	Class B Common Units	General Partner(a)	Total Cash Distribution
02/14/03	$0.3625	$ 9,918	$ 4,118	$ 5,677	$ 1,321	$ 21,034
05/15/03	0.3750	10,260	4,260	5,873	1,548	21,941
08/14/03	0.3900	10,670	4,430	6,108	1,820	23,028
11/14/03	0.4050	11,081	4,601	6,343	2,499	24,524
Total	$1.5325	$ 41,929	$17,409	$24,001	$ 7,188	$ 90,527
02/13/04	$0.4150	$ 18,020	$ 4,714	$ —	$ 3,066	$ 25,800
05/14/04	0.4250	19,661	3,621	—	3,613	26,895
08/13/04	0.4350	20,994	3,706	—	4,313	29,013
11/12/04	0.4450	25,739	3,791	—	5,705	35,235
Total	$1.7200	$ 84,414	$15,832	$ —	$16,697	$116,943
02/14/05	$0.4563	$ 26,390	$ 3,887	$ —	$ 5,201	$ 35,478
05/13/05	0.4800	29,127	2,726	—	6,778	38,631
08/12/05	0.4975	30,189	2,825	—	7,939	40,953
11/14/05	0.5312	32,236	3,018	—	10,178	45,432
Total	$1.9650	$117,942	$12,456	$ —	$30,096	$160,494

(a) Includes amounts paid to our general partner for its incentive distribution rights.

On February 14, 2006, we paid cash distributions of $0.5525 per unit on our outstanding common and subordinated units to unitholders of record at the close of business on January 30, 2006. The total distribution, including distributions paid to our general partner on its equivalent units, was $49.5 million. In February 2006, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

22. Net Income Per Unit

The following table provides details of the basic and diluted net income per unit computations (in thousands, except per unit amounts):

	For The Year Ended December 31, 2003		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$ 90,191		
Basic net income per limited partner unit	$ 90,191	54,390	$1.66
Effect of dilutive restrictive unit grants	—	80	—
Diluted net income per limited partner unit	$ 90,191	54,470	$1.66

	For The Year Ended December 31, 2004		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$101,140		
Basic net income per limited partner unit	$101,140	58,716	$1.72
Effect of dilutive restrictive unit grants	—	128	—
Diluted net income per limited partner unit	$101,140	58,844	$1.72

	For The Year Ended December 31, 2005		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$135,579		
Basic net income per limited partner unit	$135,579	66,361	$2.04
Effect of dilutive restrictive unit grants	—	264	(.01)
Diluted net income per limited partner unit	$135,579	66,625	$2.03

Units reported as dilutive securities are related to restricted unit grants associated with unvested awards (see Note 16—Long-Term Incentive Plan).

23. Partners' Capital

In June 2003, Williams sold its ownership interests in us to MGG. In that transaction, MGG acquired 2,159,388 common units, 11,359,388 subordinated units and 15,661,848 class B common units representing limited partner interest in us. These units along with MGG's 2% general partner ownership interest, represented a combined ownership interest in us of 55%. Changes in MGG's ownership interest in us since June 2003 are listed below. We received none of the proceeds from any of MGG's unit sales.

- In December 2003, our 15,661,848 class B common units, which were owned by MGG, converted into common units. Also in December 2003, MGG sold 8,600,000 common units representing limited partner interests in us.
- In January 2004, MGG sold 1,350,000 common units representing limited partner interests in us.
- In February 2004, one day after our quarterly cash distribution record date, 2,839,846 of our outstanding subordinated units owned by MGG converted into common units as provided in our partnership agreement.
- In May 2004, MGG sold 4,700,000 common units representing limited partner interests in us.

- In August 2004, MGG sold 540,000 units representing limited partner interests in us.
- In January 2005, MGG sold 5,471,082 common units representing limited partner interests in us.
- In February 2005, one day after our quarterly cash distribution record date, 2,839,846 of our subordinated units owned by MGG converted into common units as provided in our partnership agreement. Also, in February 2005, MGG sold 450,288 common units representing limited partner interests in us.
- In April 2005, MGG sold 5,679,696 subordinated units representing limited partner interests in us in a privately negotiated transaction.
- During May and June 2005, MGG sold its remaining 2,389,558 common units representing limited partner interests in us in privately negotiated transactions.

Upon consummation of the above-noted April 2005 sale of our common units by MGG, more than 50% of the total interests in our capital and profits had been sold or exchanged over the past 12-month period due to the trading activity of our limited partner units. Because of this, we were considered to have been terminated for federal income tax purposes and immediately reconstituted as a new partnership. Among other things, the termination caused a significant reduction in the amount of depreciation deductions allocable to unitholders in 2005. As a result, for only the 2005 tax year our unitholders as of April 2005 were allocated an increased amount of federal taxable income as a percentage of cash distributed to our unitholders.

All of our 60,680,928 common units and 5,679,696 subordinated units outstanding at December 31, 2005 were held by the public. The 2% general partner interest in us is owned by MGG.

Our subordination period ended on December 31, 2005, when we met the final financial tests provided for in our partnership agreement. As a result, on January 31, 2006, one day following the distribution record date, the 5,679,696 outstanding subordinated units representing limited partner interests in us converted to common units.

The limited partners holding our common 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 66.7% majority vote of outstanding unitholders;
- right to transfer common 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 on any meeting that may be called by our general partner; and
- right to inspect our books and records at the unitholders' own expense.

Cash distributions to our general partner and limited partners are made based on the following table:

	Percentage of Distributions		
		General Partner	
Quarterly Distribution Amount per Unit	Limited Partners	General Partner Interest	Incentive Distribution Rights
Up to $0.289	98%	2%	0%
Above $0.289 up to $0.328	85%	2%	13%
Above $0.328 up to $0.394	75%	2%	23%
Above $0.394	50%	2%	48%

In the event of liquidation, all property and cash in excess of that required to discharge all liabilities will be distributed to the partners in proportion to the positive balances in their respective tax-basis capital accounts. The limited partners' liability is generally limited to their investment.

24. Subsequent Events

On February 16, 2006, our general partner issued 168,105 phantom unit award grants pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant are based on the attainment of long-term performance metrics. The number of phantom units that could ultimately be issued under this award range from zero units up to a total of 336,210 units; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 20%. These unit awards will vest on December 31, 2008.

On February 14, 2006, we paid cash distributions of $0.5525 per unit on our outstanding common and subordinated units to unitholders of record at the close of business on January 30, 2006. The total distribution, including distributions paid to our general partner on its equivalent units, was $49.5 million.

During February 2006, MGG sold 35% of its MGG common units in an initial public offering. We did not receive any of the proceeds from MGG's initial public offering and do not expect our ownership structure or operations to be materially impacted by this transaction. In connection with the closing of this offering, we amended our partnership agreement to remove the requirement for our general partner to maintain its 2% interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

We had a terminalling agreement under which we provided storage rental and throughput fees based on discounted rates plus a variable fee, which was based on a percentage of the net profits from certain trading activities conducted by our customer. Under this agreement, which expired on January 31, 2006, we recognized the discounted storage rental and throughput fees as the services were performed; however, we would not receive revenue from the variable fee if the net trading profits fell below a specified amount or were negative. We earned approximately $6.4 million related to the shared trading profits which was not determinable until the end of the contract term. We elected to defer the recognition of this revenue until the end of the contract term. As a result of settling this agreement, our terminal revenues, operating profit and net income will be favorably impacted by approximately $6.4 million during the first quarter of 2006.

On January 31, 2006, one day after our quarterly cash distribution record date, all of our 5,679,696 outstanding subordinated units converted to common units as provided in our partnership agreement.

On January 13, 2006, we experienced a line break and product release of approximately 3,200 barrels from our petroleum products pipeline near Independence, Kansas. We are in the process of estimating the repair and remediation costs associated with the release. We have insurance coverage for this incident with a deductible of $1.5 million. We are unable to estimate with any degree of certainty what penalties, if any, might be assessed by the EPA or other governmental agency, associated with this release, which would not be covered by our insurance policy. Our net cost for repair and remediation plus any penalties that may be assessed could be material to our results of operations or cash flows.

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

None.

ITEM 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including the General Partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, the 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 has been no change in our internal control over financial reporting (as defined in Rule 13a – 15(f) of the Securities and Exchange Act) during the quarter ended December 31, 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Our management, including our general partner's Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal control over financial reporting ("internal control") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. 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 controls and internal control and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal control will be maintained as systems change and conditions warrant.

ITEM 9B. ***Other Information***

None.

PART III

ITEM 10. ***Directors and Executive Officers of the Registrant***

The information regarding the directors and executive officers of our general partner required by Item 401 of Regulation S-K is presented in our proxy statement prepared for the solicitation of proxies in connection with our Annual Meeting of Limited Partners for 2006 (our "Proxy Statement") under the captions "Class I Director Election Proposal" and "Executive Officers of our General Partner", which information is incorporated by reference herein. Information required by Item 405 of Regulation S-K is presented under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement, which information is incorporated by reference herein. Information required by Item 406 of Regulation S-K is presented under the caption "Code of Ethics" in our Proxy Statement, which information is incorporated by reference herein.

ITEM 11. ***Executive Compensation***

The information regarding executive compensation required by Item 402 of Regulation S-K is presented in our Proxy Statement under the caption "Executive Compensation," which information is incorporated by reference herein.

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 required by Item 201(d) of Regulation S-K is presented in our Proxy Statement under the caption "Equity Compensation Plans," which information is incorporated by reference herein. Information required by Item 403 of Regulation S-K is presented under the caption "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

ITEM 13. ***Certain Relationships and Related Transactions***

The information regarding certain relationships and related transactions required by Item 404 of Regulation S-K is presented in our Proxy Statement under the caption "Certain Relationships and Related Transactions," which information is incorporated by reference herein.

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 is presented in our Proxy Statement under the caption "Independent Registered Public Accounting Firm," which information is incorporated by reference herein.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

(a) 1 and 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 and (c). The exhibits listed below are filed as part of this annual report.

Exhibit No.	Description
Exhibit 2	
*(a)	Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 99.1 to Form 8-K of The Williams Companies, Inc. filed April 21, 2003).
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Exhibit No.	Description
*(f)	Second Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated as of October 20, 2005 (filed as Exhibit 3.1 to Form 8-K filed October 25, 2005).
Exhibit 4	
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*(c)	Magellan 401(k) Plan (filed as Exhibit 10(c) to Form 10-K filed March 10, 2004).
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*(h)	Summary of Independent Director Compensation Program (filed as Exhibit 10.1 to Form 8-K/A filed February 3, 2005).
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*(j)	Services Agreement dated December 24, 2005 between Magellan Midstream Partners, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 10.1 to Form 8-K filed December 27, 2005).

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*(l)	First Amendment dated September 9, 2004 to Credit Agreement dated May 25, 2004 among Magellan Midstream Partners, L.P., the lenders party thereto, JPMorgan Chase Bank, as Administrative Agent, and J.P. Morgan Securities Inc. and Lehman Brothers Inc., as Joint Bookrunners and Lead Arrangers (filed as Exhibit 10.1 to Form 10-Q filed November 4, 2004).
*(m)	Amended and Restated Note Purchase Agreement dated May 25, 2004 among Magellan Pipeline Company, LLC, Magellan Midstream Partners, L.P. and Magellan GP, LLC and each of the Holders thereto (filed as Exhibit 10.2 to Form 10-Q filed August 6, 2004).
*(n)	Consent and Amendment dated August 30, 2004 to Amended and Restated Note Purchase Agreement dated May 25, 2004 among Magellan Pipeline Company, LLC, Magellan Midstream Partners, L.P. and Magellan GP, LLC and each of the Holders thereto (filed as Exhibit 10.2 to Form 10-Q filed November 4, 2004).
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*(q)	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).
*(r)	Agreement for the Release of Certain Indemnification Obligations dated May 26, 2004 among Magellan Midstream Holdings, L.P., Magellan GP, LLC and Magellan Midstream Partners, L.P. and The Williams Companies, Inc., Williams Energy Services, LLC, and Williams Natural Gas Liquids, Inc. and Williams GP LLC (filed as Exhibit 10.3 to Form 10-Q filed August 6, 2004).
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
*(a)	Code of Ethics dated September 1, 2003 by Don R. Wellendorf, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed March 10, 2004).
*(b)	Code of Ethics dated September 1, 2003 by John D. Chandler, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed March 10, 2004).
Exhibit 21	Subsidiaries of Magellan GP, LLC and Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
(a)	Certification of Don R. Wellendorf, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
(b)	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 99	Magellan GP, LLC consolidated balance sheets at December 31, 2005 and 2004 and notes thereto.

* 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/ LONNY E. TOWNSEND
Lonny E. Townsend
Vice President and General Counsel

Date: March 13, 2006

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/ DON R. WELLENDORF **Don R. Wellendorf**	Chairman of the Board, President, Chief Executive Officer and Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ JOHN D. CHANDLER **John D. Chandler**	Vice President, Treasurer and Chief Financial Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ JIM H. DERRYBERRY **Jim H. Derryberry**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ JOHN P. DESBARRES **John P. DesBarres**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ PATRICK C. EILERS **Patrick C. Eilers**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ N. JOHN LANCASTER, JR. **N. John Lancaster, Jr.**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ JAMES R. MONTAGUE **James R. Montague**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ GEORGE A. O'BRIEN, JR. **George A. O'Brien, Jr.**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006
/s/ THOMAS S. SOULELES **Thomas S. Souleles**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	March 13, 2006

INDEX TO EXHIBITS

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*(m)	Amended and Restated Note Purchase Agreement dated May 25, 2004 among Magellan Pipeline Company, LLC, Magellan Midstream Partners, L.P. and Magellan GP, LLC and each of the Holders thereto (filed as Exhibit 10.2 to Form 10-Q filed August 6, 2004).

Exhibit No.	Description
*(n)	Consent and Amendment dated August 30, 2004 to Amended and Restated Note Purchase Agreement dated May 25, 2004 among Magellan Pipeline Company, LLC, Magellan Midstream Partners, L.P. and Magellan GP, LLC and each of the Holders thereto (filed as Exhibit 10.2 to Form 10-Q filed November 4, 2004).
*(o)	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).
*(p)	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).
*(q)	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).
*(r)	Agreement for the Release of Certain Indemnification Obligations dated May 26, 2004 among Magellan Midstream Holdings, L.P., Magellan GP, LLC and Magellan Midstream Partners, L.P. and The Williams Companies, Inc., Williams Energy Services, LLC, and Williams Natural Gas Liquids, Inc. and Williams GP LLC (filed as Exhibit 10.3 to Form 10-Q filed August 6, 2004).
Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
*(a)	Code of Ethics dated September 1, 2003 by Don R. Wellendorf, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed March 10, 2004).
*(b)	Code of Ethics dated September 1, 2003 by John D. Chandler, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed March 10, 2004).
Exhibit 21	Subsidiaries of Magellan GP, LLC and Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
(a)	Certification of Don R. Wellendorf, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
Exhibit 32	
(a)	Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
(b)	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 99	Magellan GP, LLC consolidated balance sheets at December 31, 2005 and 2004 and notes thereto.

* 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.