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, 2003

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 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 an accelerated filer (as defined in Exchange Act Rule 12b-2). ☒

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, 2003, was $595.7 million.

As of March 1, 2004, there were outstanding 23,130,541 common units and 4,259,771 subordinated units.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2004 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. On September 1, 2003, our name changed from Williams Energy Partners L.P. (NYSE:WEG) to Magellan Midstream Partners, L.P. (NYSE:MMP). We were formed when The Williams Companies, Inc. ("Williams") contributed certain entities, which included terminal and ammonia pipeline assets to us. The principal executive offices of Magellan GP, LLC, our general partner, are located at One Williams Center, Tulsa, Oklahoma 74172 (telephone (918) 574-7000).

A discussion of our acquisition of Magellan Pipeline Company, LLC ("Magellan Pipeline") is included under the caption "Introduction" in Management's Discussion and Analysis of Financial Condition and Results of Operations. In addition, a brief description of all the acquisitions completed by the Partnership since our initial public offering can be found under the caption "Acquisition History" in Management's Discussion and Analysis of Financial Condition and Results of Operations.

During 2003, Williams agreed to sell their approximate 54.6% interest in us to Magellan Midstream Holdings, L.P. ("MMH"), formerly known as WEG Acquisitions, L.P., a Delaware limited partnership formed by Madison Dearborn Capital Partners IV, L.P. and Carlyle/Riverstone MLP Holdings, L.P. On June 17, 2003, Williams' sale was consummated and MMH purchased all of the limited partner interests in us owned by Williams through its subsidiaries and all of the membership interests in our general partner. These limited partner interests consisted of 1,079,694 common units, 5,679,694 subordinated units and 7,830,924 class B common units. Through its purchase of all of the membership interests in our general partner, MMH also became the indirect owner of a 2% general partner interest in us and all of our incentive distribution rights, which entitle the holder to an increasing percentage of our cash distributions as we increase distributions to our common unitholders.

In connection with the sale of Williams' interests in us, six of the seven directors resigned from our general partner's board of directors and four directors affiliated with MMH were appointed to our general partner's board. Mr. Don R. Wellendorf, our general partner's Chief Executive Officer and President, is the Chairman of the Board and continued to serve in these capacities. Prior to December 31, 2003, our general partner's board increased the size of the board to eight and appointed three directors that meet the independence and financial literacy requirements of the New York Stock Exchange ("NYSE") and the Securities and Exchange Commission ("SEC").

In November 2003, our common unitholders approved the conversion of each outstanding class B common unit into one common unit, and the resulting issuance of an aggregate of 7,830,924 common units upon the request by MMH, the holder of those units, for the conversion and cancellation of the 7,830,924 class B common units. On December 1, 2003, MMH requested the conversion of all of the class B common units and the units were then converted into common units. In late December 2003 and early January 2004, MMH sold 4,975,000 common units and we sold 200,000 common units in an underwritten public offering. On February 7, 2004, pursuant to Section 5.8(a) of our Second Amended and Restated Agreement of Limited Partnership, 1,419,923 of the 5,679,694 subordinated units held by MMH converted into common units on a one-for-one basis. As of the date of this annual report on Form 10-K, MMH's limited partner interests in us consist of 5,355,541 common units and 4,259,771 subordinated units, which represents an approximate 36.4% ownership interest in us, including MMH's 2% general partner interest.

(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 storage, transportation and distribution of refined petroleum products and ammonia. Our asset portfolio currently consists of:

- a 6,700-mile petroleum products pipeline system, including 39 petroleum products terminals serving the mid-continent region of the United States. Of these terminals, we own 38 and have an access agreement to a third-party terminal;
- five petroleum products terminal facilities located along the Gulf Coast and near the New York harbor. We refer to these facilities as our marine terminals;
- 29 petroleum products terminals located principally in the southeastern United States, which we refer to as our inland terminals. Our inland terminals include 6 terminals acquired in January 2004. Also during January 2004, we acquired the remaining 21% ownership interests in 8 terminals in which we previously owned a 79% ownership interest. See *Recent Developments* in Management's Discussion and Analysis for further discussion of the acquisition of these terminals; and
- an ammonia pipeline system, which extends approximately 1,100 miles from Texas and Oklahoma to Minnesota.

Petroleum Products Transportation and Distribution

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 market 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, jet fuel, kerosene and heating oil;
- *liquefied petroleum gases, or LPGs,* which are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;
- *blendstocks,* which are blended with petroleum products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates and oxygenates;
- *heavy oils and feedstocks,* which are used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include # 6 fuel oil and vacuum gas oil; and
- *crude oil and condensate,* which are used as feedstocks by refineries.

PETROLEUM PRODUCTS PIPELINE SYSTEM

Our petroleum products pipeline system covers an 11-state area, extending from Oklahoma through the Midwest to North Dakota, Minnesota and Illinois. Our pipeline system transports petroleum products and LPGs and includes a common carrier pipeline and 39 terminals that provide transportation and terminals services. The products transported on our pipeline system are largely transportation fuels, and in 2003 were comprised of 58%

gasoline, 33% distillates (which includes diesel fuels and heating oil) and 9% 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. See Note 16—Segment Disclosures in the accompanying consolidated financial statements.

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 market area 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 1.7% 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.

Our petroleum products pipeline system is well connected to Gulf Coast refineries through interconnections with the Explorer, Shell, 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 it 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 1.4% from 2001 to 2003. The volume increases have come through a combination of overall market demand growth, development projects on our system and from incentive agreements with shippers utilizing our system. The operating statistics below reflect our petroleum products pipeline system's operations for the periods indicated:

	2001	2002	2003
Shipments (thousands of barrels):			
Refined products			
Gasoline	137,552	139,073	137,752
Distillates	75,887	73,559	78,264
Aviation fuel	14,752	14,081	13,691
LPGs	7,901	7,910	7,922
	236,092	234,623	237,629
Capacity lease	23,671	25,465	25,647
Total shipments	259,763	260,088	263,276
Daily average (thousands of barrels)	712	713	721
Barrel miles (billions)	70.5	71.0	70.5

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 of refined petroleum products and LPGs in the United States in terms of pipeline miles and the fifth largest based on deliveries. Through direct refinery connections and interconnections with other interstate pipelines, our system can access approximately 41% of the refinery capacity in the continental United States. In general, we do not take title to the petroleum products we transport.

Our petroleum products pipeline system generates approximately 81% of its revenue, excluding product sales revenue, 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 our pipeline system's 39 terminals. Currently, the tariffs we charge to shippers for transportation of products generally do not vary according to the type of products transported. 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 53% of the shipments in 2003 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.

Our petroleum products pipeline system generates the remaining 19% 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. In addition, we began operating the Rio Grande pipeline system in 2003 and on January 1, 2004 began serving as a subcontractor to an affiliate of Williams for the interim operations of Longhorn Partners Pipeline, L.P. until its anticipated start-up in the second quarter of 2004. We are receiving a monthly fee for both of these services.

Product sales revenues result from the sale of products that are produced from fractionating transmix and from our petroleum products management operation. We take title to the products related to these activities. While the revenues generated from these activities were over $108.0 million in 2003, margins from these sales were only $9.7 million. Revenues and margins from these activities increased in 2003 over 2002 by $38.5 million and $4.5 million, respectively, primarily as a result of our purchase of the petroleum products management operation from Williams in July 2003.

Facilities

Our petroleum products pipeline system consists of a 6,700-mile pipeline and includes 22.5 million barrels of aggregate usable storage capacity at terminals and various pump stations. The terminals deliver petroleum products primarily into tank trucks, although two terminals can load into tank rail cars.

The following table contains information regarding our owned terminal facilities:

Delivery Points	Total Usable Storage Capacity (barrels in thousands)	Delivery Points	Total Usable Storage Capacity (barrels in thousands)
Arkansas		Minnesota (cont.)	
Ft. Smith	178	Minneapolis	1,826
Illinois		Rochester	135
Amboy	186	Missouri	
Chicago	542	Carthage	117
Heyworth	368	Columbia	284
Menard County	217	Palmyra	171
Iowa		Springfield	286
Des Moines	1,965	Nebraska	
Dubuque	95	Capehart	100
Ft. Dodge	128	Doniphan	500
Iowa City	656	Lincoln	137
Mason City	607	Omaha	940
Milford	179	North Dakota	
Sioux City	559	Fargo	589
Waterloo	353	Grand Forks	327
Kansas		Oklahoma	
Kansas City	1,601	Enid	290
Olathe	202	Oklahoma City	290
St. Joseph	78	Tulsa	1,879
Topeka	142	South Dakota	
Minnesota		Sioux Falls	623
Alexandria	611	Watertown	209
Mankato	416	Wisconsin	
Marshall	182	Wausau	150
		Pump Stations	4,366
		Total	22,484

In addition, we have an agreement with ConocoPhillips, which provides us the right to use their terminal facility at Wichita, Kansas.

Petroleum Products Supply

Petroleum products originate from both refining and pipeline interconnection points along our pipeline system. In 2003, 55% of the petroleum products transported on our petroleum products pipeline system originated from 10 direct refinery connections and 45% originated from 12 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
ConocoPhillips	Ponca City, OK
Farmland Industries, Inc	Coffeyville, KS
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. Product from Explorer can be transferred into our pipeline system for delivery into the mid-continent and northern-tier states. Our pipeline system is also connected to all Chicago area refineries through the West Shore Pipe Line.

Major Origins—Pipeline Connections (Listed Alphabetically)

Pipeline	Connection Location	Source of Product
BP	Manhattan, IL	Whiting, IN refinery
Buckeye	Mazon, IL	East Chicago, IL storage
Cenex	Fargo, ND	Laurel, MT refinery
CITGO Pipeline	Drumright, OK	Various Gulf Coast refineries
ConocoPhillips	Kansas City, KS	Various Gulf Coast refineries (via Seaway/Standish Pipeline); Borger, TX refinery
Explorer Pipeline	Glenpool, OK; Mt. Vernon, MO	Various Gulf Coast refineries
Kaneb Pipeline	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 area refineries
Mid-America Pipeline (Enterprise)	El Dorado, KS	Conway, KS storage
Orion Pipeline (Equilon)	Duncan, OK	Various Gulf Coast refineries
Total (Valero)	Wynnewood, OK	Ardmore, OK refinery
West Shore Pipe Line	East 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.

For the year ended December 31, 2003, 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, 2003, represented 49% of total revenues for our petroleum products pipeline system and 64% of revenues excluding product sales.

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 terminal facilities are located in close proximity to refineries and are large storage and distribution facilities that handle refined petroleum products, blendstocks, heavy oils, feedstocks, crude oil and condensate. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as Colonial, Explorer, Plantation and TEPPCO. Our facilities receive products from pipelines and distribute them to third parties at the terminals, which in turn deliver them to end-users such as retail outlets. Because these terminals are unregulated, the marketplace determines the prices we can charge for our services.

In 2003, Williams and its affiliates significantly reduced their storage and throughput volumes at our petroleum products terminals. As a result, affiliate revenues with Williams and its affiliates accounted for only 7% of petroleum products terminals' 2003 revenues as compared to 21% in 2002. Please read Note 11 – Related Party Transactions in the accompanying consolidated financial statements.

Marine Terminal Facilities

The Gulf Coast region is a major hub for petroleum refining, representing approximately 43% of total U.S. daily refining capacity and 67% of U.S. refining capacity expansion from 1990 to 2002. 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. From 1990 to 2002, the amount of petroleum products exported from the Gulf Coast region increased by approximately 18%, or 195 million barrels. The growth in refining capacity and increased product flow attributable to the Gulf Coast region has created a need for additional transportation, storage and distribution facilities. In the future, competition resulting from the consolidation trend, combined with continued environmental pressures, continuation of imports, governmental regulations and market conditions, could result in the closing of smaller, less economical inland refiners, creating even greater demand for petroleum products refined in the Gulf Coast region.

We own and operate five marine terminal facilities, including four marine terminal facilities located along the Gulf Coast and one terminal facility located in Connecticut near the New York harbor. Our marine terminals are large storage and distribution facilities, with an aggregate storage capacity of approximately 16.6 million barrels, that provide inventory management, storage and distribution services for refiners and other large end-users of petroleum products.

Our marine terminal facilities 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 railcar. Once the product has reached our marine terminal facilities, we store the product for a period of time ranging from a few days to several months. Products that we store include petroleum products, blendstocks, heavy oils and feedstocks.

In addition to providing storage and distribution services, our marine terminal facilities provide ancillary services including heating, blending and mixing of stored products and injection services. Many heavy oils require heating to keep them in a liquid state. Further, in order to meet government specifications, products often must be combined with other products through the blending and mixing process. Blending is the combining of products from different storage tanks. Once the products are blended together, the mixing process circulates the blended product through mixing lines and nozzles to further combine the products. Injection is the process of injecting refined petroleum products with additives and dyes to comply with governmental regulations and to meet our customers' marketing initiatives.

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 facilities. Refiners and chemical companies will typically use our marine terminal facilities 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.

The following table outlines our marine terminal facilities' usable storage capacities, primary products handled and the connections to and from these terminals:

Facility	Usable Storage Capacity (Thousand Barrels)	Primary Products Handled	Connections
Connecticut			
New Haven	3,556	Refined petroleum products, ethanol, feedstocks and asphalt	Pipeline, barge, ship and truck
Louisiana			
Gibson	56	Crude oil and condensate	Pipeline, barge and truck
Marrero	1,598	Heavy oils and feedstocks	Barge, ship, rail and truck
Texas			
Corpus Christi	2,594	Blendstocks, heavy oils and feedstocks	Pipeline, barge, ship and truck
Galena Park	8,788	Refined petroleum products, blendstocks, heavy oils and feedstocks	Pipeline, barge, ship, rail and truck
Total storage capacity	16,592		

Customers and Contracts

We have long-standing relationships with oil refiners, suppliers and traders at our facilities, and most of our customers have consistently renewed their short-term contracts. During 2003, approximately 93% of our marine terminal capacity was utilized. As of December 31, 2003, approximately 59% 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. Our long-term contract with Williams Energy Marketing & Trading, LLC ("WEM&T"), which represented approximately 19% of revenues at our marine terminal facilities for the year ended December 31, 2002, was terminated during the first quarter of 2003. We received $3.0 million from WEM&T to cancel this contract and recognized that amount as revenue during the first quarter of 2003. As a result, WEM&T accounted for 8% of our total marine revenues for 2003. However, excluding this settlement payment from revenues would have resulted in WEM&T accounting for only 4% of our total marine revenues for 2003. For a further discussion of revenues from major customers, refer to Note 9 – Major Customers and Concentration of Risk in the accompanying consolidated financial statements. Also, please read Note 11 – Related Party Transactions in the accompanying consolidated financial statements for additional information regarding affiliate revenues.

Markets and Competition

We believe that the strong demand for our marine terminal facilities from our refining and chemical customers, resulting from our cost-effective distribution services and key transportation links will continue. We experience the greatest demand at our marine terminal facilities 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, several companies have facilities in the Gulf Coast region and 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 6 of these terminals in January 2004 and also acquired the remaining 21% ownership interest in 8 terminals in which we previously had a 79% ownership interest. As a result, we now wholly own 26 of the 29 terminals in our portfolio. Our terminals have a combined storage capacity of 5.4 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, Plantation, TEPPCO or Explorer pipelines and some facilities have multiple pipeline connections. In addition, our Dallas terminal connects to Dallas Love Field airport via a 6-inch pipeline we purchased in April 2001. During 2003, gasoline represented approximately 56% of the product volume distributed through our inland terminals, with the remaining 44% consisting of distillates.

Our inland terminal facilities 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 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 jet fuel, and for filtering jet fuel. Our inland terminals are equipped with automated loading facilities that are available 24 hours a day.

In January 2004, we increased the number of terminals we wholly own from 12 to 26. Additionally, we have ownership interests in 3 inland terminals that range from 50% to 60%. The following table sets forth our inland terminal locations, percentage ownership, usable storage capacities and methods of supply:

Facility	Percentage Ownership	Total Usable Capacity (Thousand Barrels)		Connections
Alabama				
Birmingham	100	95	*	Colonial and Plantation Pipelines
Montgomery	100	94		Plantation Pipeline
Arkansas				
North Little Rock	100	167		TEPPCO Pipeline
South Little Rock	100	224		TEPPCO Pipeline
Georgia				
Albany	100	119	**	Colonial Pipeline
Doraville	100	267		Colonial and Plantation Pipelines
Doraville	100	315	*	Colonial and Plantation Pipelines
Macon	100	130	*	Colonial and Plantation Pipelines
Missouri				
St. Charles	100	201		Explorer and ConocoPhillips Pipelines
North Carolina				
Charlotte	100	284		Colonial Pipeline
Charlotte	100	142	**	Colonial Pipeline
Greensboro	60	228		Colonial Pipeline
Greensboro	100	228	**	Colonial and Plantation Pipelines
Selma	100	289	**	Colonial Pipeline
South Carolina				
North Augusta	100	150	**	Colonial Pipeline
North Augusta	100	116		Colonial Pipeline
Spartanburg	100	110		Colonial Pipeline
Spartanburg	100	152	*	Colonial Pipeline
Tennessee				
Chattanooga	100	132		Colonial Pipeline
Chattanooga	100	212	*	Colonial and Plantation Pipelines
Knoxville	100	106		Colonial and Plantation Pipelines
Knoxville	100	183	*	Colonial and Plantation Pipelines
Nashville	50	226		Colonial Pipeline and barge
Nashville	100	147		Colonial Pipeline
Nashville	100	123	**	Colonial Pipeline
Texas				
Dallas	100	387		Explorer, Magtex and Dallas Love Field Pipelines
Southlake	50	246		Explorer, Koch and Valero Pipelines
Virginia				
Montvale	100	159	**	Colonial Pipeline
Richmond	100	157	**	Colonial Pipeline
Total		5,389		

* We acquired sole ownership in these 6 of terminals in January 2004 from Murphy Oil USA Inc. and Colonial Pipeline Company.

** We previously owned a 79 percent interest in these 8 of terminals and purchased the remaining interest from Murphy Oil USA, Inc. in January 2004.

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 separate 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 that sell gasoline and other petroleum products through proprietary retail networks;
- wholesalers that sell petroleum products to retailers as well as to large commercial and industrial end-users;
- exchange transaction customers, where we act as an intermediary so that the parties to the transaction are able to exchange petroleum products; and
- traders that arbitrage, trade and market products stored in our terminals.

Due to the change in our relationship with Williams and the sales of its Memphis, Tennessee refinery and travel center operations, Williams and its affiliates accounted for only 3% of our 2003 inland terminal revenues as compared to 25% in 2002. See Note 11 – Related Party Transactions in the accompanying consolidated financial statements.

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 from independent operators primarily comes from distribution companies with marketing and trading arms, independent terminal operators and refining and marketing companies.

AMMONIA PIPELINE SYSTEM

We own a 1,100-mile ammonia pipeline system. Our pipeline system transports ammonia from production facilities in Texas and Oklahoma to terminals in the Midwest for ultimate distribution to end-users in Iowa, Kansas, Minnesota, Missouri, Nebraska, Oklahoma and South Dakota. The ammonia we transport is primarily used as a nitrogen fertilizer. Nitrogen is an essential nutrient for plant growth and is the single most important element for maintenance of high crop yields for all grains. Unlike other primary nutrients, however, nitrogen must be applied each year because virtually all of its nutritional value is consumed during the growing season. Ammonia is the most cost-effective source of nitrogen and the simplest nitrogen fertilizer. It is also the primary feedstock for the production of upgraded nitrogen fertilizers and chemicals.

Ammonia is produced by reacting natural gas with air at high temperatures and pressures in the presence of catalysts. Because natural gas is the primary feedstock for the production of ammonia, ammonia is typically produced near abundant sources of natural gas. Natural gas prices exhibited strong volatility in late 2002 and early 2003, increasing to unprecedented high levels. This caused the shippers to substantially curtail production at their facilities and shipments on our pipeline system during early 2003. Although natural gas prices remain above historical levels, they dropped below these unprecedented high levels during the latter part of the first quarter of 2003 and our shippers resumed shipments at close to historical levels.

Operations

We are a common carrier transportation pipeline and terminals company. We earn revenue from transportation tariffs for the use of our pipeline capacity and throughput fees at our six ammonia terminals. We do not produce or trade ammonia, and we do not take title to the ammonia we transport.

We generate approximately 93% of our revenue 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, including unloading ammonia from our customers' trucks to inject it into our pipeline for shipment and removing ammonia from our pipeline to load it into our customers' trucks.

Beginning in February 2003, a third-party pipeline company began providing the operating and general and administrative services for our ammonia pipeline system under an operating agreement with us.

Facilities

Our ammonia pipeline was the world's first common carrier pipeline for ammonia. The main trunk line was completed in 1968. Today, it represents 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 6 facilities 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 such as urea, ammonium nitrate, ammonium phosphate and ammonium sulfate.

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. The transportation contracts with our customers extend through June 2005. Our customers are obligated to ship an aggregate minimum of 450,000 tons per year but can commit to a higher annual volume to receive a lower tariff rate (see *Farmland/Koch* discussion below). Our customers, or their predecessors, have been shipping ammonia through our pipeline for an average of more than 20 years.

Each transportation contract contains a ship or pay mechanism whereby each customer must ship a specific minimum tonnage per year and an aggregate minimum tonnage over the life of the contract. On July 1 of each contract year, each of our customers nominates a tonnage that it expects to ship during the upcoming year. This annual commitment may be equal to or greater than the contractual minimum tonnage. Our customers' aggregate annual commitments for the period July 1, 2003 through June 30, 2004 are 550,000 tons. If a customer fails to ship its annual commitment, that customer must pay for the pipeline capacity it did not use (see *Farmland/Koch* discussion below). We allow our customers to bank any ammonia shipped in excess of their annual commitments. If a customer has previously shipped an amount in excess of its annual commitment, the shipper may offset subsequent annual shipment shortfalls against the excess tonnage in its bank. There are approximately 185,000 tons in this combined bank that may be used to offset future ship or pay obligations. We have the right to adjust our tariff schedule on an annual basis pursuant to a formula contained in the contracts. Any annual adjustment is limited to a maximum increase or decrease of 5% measured against the rate previously in effect.

Farmland/Koch. On May 31, 2002, Farmland Industries, Inc. ("Farmland") and several of its subsidiaries filed for Chapter 11 bankruptcy protection. In December 2002, Farmland, the largest customer on the ammonia pipeline system, announced its intent to sell its ammonia production facility connected to our pipeline to Koch Nitrogen Company ("Koch") and elected to exercise its rights under our ammonia pipeline agreement to terminate its shipment obligation by submitting 12-month written notice to us. Farmland's notification was to be effective December 23, 2002. Farmland was expected to incur a deficiency of approximately $2.0 million to $2.5 million under its shipment obligation for the contract year beginning July 1, 2002 and ending June 30, 2003. On February 18, 2003, we entered into a settlement agreement with Farmland to resolve the deficiency and provide the basis for assignment of its shipment obligation to the ultimate purchaser of its ammonia assets pursuant to bankruptcy procedures. Under the settlement agreement, Farmland paid us $0.8 million for the deficiency it would have incurred under its shipment obligation for the contract year ending June 30, 2003. On May 19, 2003, Koch Nitrogen Company purchased, with approval from the bankruptcy court, selected U.S. fertilizer assets from Farmland including the Enid production facility and other facilities along our pipeline system. As part of this transaction, Farmland withdrew its termination notice and assigned its shipment obligation with the revised requirements of 200,000 tons annually versus the previous requirement of 450,000 tons annually per the settlement agreement. The revised shipment obligation of Koch has reduced the aggregate minimum shipment obligations on the pipeline system from 700,000 tons annually to 450,000 tons annually.

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 high 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, but we believe we have a distinct advantage over rail carriers because ammonia is a gas under normal atmospheric conditions and must be placed under pressure or cooled to -33 degrees Celsius to be shipped or stored. 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 Kaneb's ammonia pipeline, which originates on the Gulf Coast and transports domestically produced and imported ammonia.

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 posted publicly and that these rates be "just and reasonable" and nondiscriminatory. Rates of interstate oil pipeline companies, like 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, or PPI, for finished goods 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 Washington D.C. Circuit, the FERC changed the rate indexing methodology to the PPI for finished goods, 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. 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 PPI. Approximately one-third of the 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 oil pipeline company that a rate is acceptable. Two-thirds 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 a June 1996 decision, the FERC disallowed the inclusion of a full income tax allowance in the cost-of-service tariff filing of Lakehead Pipe Line Company, L.P. ("Lakehead"), an unrelated oil pipeline limited partnership. The FERC held that Lakehead was entitled to include an income tax allowance in its cost-of-service for income attributable to corporate partners but not on income attributable to individual partners. In 1997, Lakehead reached an agreement with its shippers on all contested rates, so there was no judicial review of the FERC's decision. In January 1999, in a FERC proceeding involving SFPP, L.P. ("SFPP"), another unrelated oil pipeline limited partnership, the FERC followed its decision in Lakehead and held that SFPP may not claim an income tax allowance with respect to income attributable to non-corporate limited partners. Several parties sought rehearing of the FERC's decision in SFPP and of several FERC orders issued on rehearing in the SFPP case. Several parties have also filed appeals of the FERC's orders, which are currently being held in abeyance by the court of appeals pending resolution by the FERC of the remaining requests for rehearing. The FERC's decision in the Lakehead and SFPP proceedings should have no effect on the market-based rates we charge in competitive markets. However, the Lakehead and SFPP decisions might become relevant to our petroleum products pipeline system should we (1) elect in the future to raise our indexed rates using the cost-of-service methodology, (2) be required to use a cost-of-service methodology to defend our indexed rates against a shipper protest alleging that an indexed rate increase substantially exceeds actual cost increases, or (3) be required to defend our indexed rates against a shipper complaint alleging that the pipeline's rates are not just and reasonable. In such case, a complainant or protestant could assert that, in light of the decisions regarding Lakehead and SFPP and our ownership of the petroleum products pipeline system, we should be allowed to collect an income tax allowance only with respect to the portion of our partnership units held by corporations. We believe that most if not all of the indexed rates can be supported on a cost-of-service basis, even assuming a reduction in the income tax allowance. Nevertheless, if the indexed rates were challenged, we cannot give assurance that some or all of the indexed rates may not be reduced. If indexed rates were reduced, the amount of cash generated from our operations could be materially reduced.

The Surface Transportation Board ("STB"), a part of the United States Department of Transportation, has jurisdiction over interstate pipeline transportation of ammonia. The STB succeeded the Interstate Commerce Commission which previously regulated pipeline transportation of ammonia.

The STB is responsible for rate regulation of pipeline transportation of commodities other than water, gas or oil. These 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 it must determine whether the pipeline rates are reasonable. The Board generally applies constrained market pricing principles in its economic analysis. Constrained market pricing provides two alternative methodologies for examining the reasonableness of a carrier's rates. The first approach examines a carrier's existing system to determine whether the carrier is already earning sufficient funds to cover its costs and provide a sufficient return on investment, or would earn sufficient funds after eliminating unnecessary costs from specifically identified inefficiencies and cross-subsidies in its operations. The second approach calculates the revenue requirements that a hypothetical, new and optimally efficient carrier would need to meet in order to serve the complaining shippers.

Customers that protest rates in STB proceedings may use any methodology they choose that is consistent with constrained market pricing principles. When addressing revenue adequacy, a complainant must provide more than a single period snapshot of a carrier's costs and revenues. The complainant must measure whether a carrier earns adequate revenues over a period of time, as measured by a multi-period discounted cash flow analysis.

The STB has held that unreasonable discrimination occurs when (1) there is a disparity in rates, (2) the complaining party is competitively injured, (3) the carrier is the common source of both the allegedly prejudicial and preferential treatment and (4) the disparity in rates is not justified by transportation conditions.

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 Illinois, Kansas and Oklahoma. 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

Our pipeline systems have been constructed, operated, maintained, repaired, tested and used in general compliance with applicable federal, state and local laws and regulations, American Petroleum Institute standards and other generally accepted industry standards and practices. These pipeline systems will continue to be operated, maintained and inspected in accordance with governing regulations and industry practices.

Our pipeline systems are subject to regulation by the United States Department of Transportation under the Hazardous Liquid Pipeline Safety Act ("HLPSA") of 1979, as amended, and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of its pipeline facilities. HLPSA covers petroleum and petroleum products 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 and ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. Segments of our pipeline systems are located in high consequence areas and/or have the ability to impact high consequence areas. We believe we are in material compliance with HLPSA requirements. Since this rule went into effect, we have spent approximately $25 million relative to integrity assessment and anticipate spending approximately $36 million during the next five years associated with system integrity assessments. These cost estimates could increase in the future if additional safety measures are required or if existing safety standards are raised that exceed the current pipeline capabilities.

Our pipeline systems are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposures. The OSHA hazard communication standard, the Environmental Protection Agency ("EPA") community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act 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. In general, we expect to increase our expenditures during the next decade to comply with more strigent industry and regulatory safety standards such as those described above. At qualifying facilities, we are subject to OSHA Process Safety Management regulations that are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. We believe we are in material compliance with the OSHA Process Safety Management regulations.

Environmental

General

The operation of our pipeline systems, terminals and associated facilities in connection with the transportation, storage and distribution of refined petroleum products, crude oil and other liquid hydrocarbons and ammonia is subject to stringent and complex laws and regulations governing the discharge of materials into the environment or otherwise related to environmental protection. As an owner or lessee and operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. Compliance with existing and anticipated laws and regulations increases the cost of planning, constructing and operating pipelines, terminals and other facilities. Included in our construction and operating costs are capital cost items necessary to maintain or upgrade our equipment and facilities to comply with existing environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, imposition of remedial actions and the issuance of injunctions, or construction bans or delays on ongoing operations. Except as described below under *Environmental Liabilities Associated with Magellan Terminal Holdings and the Ammonia Pipeline System* and *Environmental Liabilities Associated with the Petroleum Products Pipeline System*, we believe that our operations are in material compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to frequent change, and we cannot give assurance that the cost to comply with these laws and regulations in the future will not have a material adverse effect on our financial position or results of operations.

Estimates provided below for remediation costs assume that we will be able to use common remedial and monitoring methods or associated engineering or institutional controls to demonstrate compliance with applicable regulatory requirements. These estimates cover the cost of performing assessment, remediation and/or monitoring of impacted soils, groundwater and surface water conditions, but do not include any costs for potential claims by others with respect to these sites. While we do not expect any such potential claims by others to be materially adverse to our operations, financial position, or cash flows, we cannot give assurance that the actual remediation costs or associated remediation liabilities will not exceed estimated amounts.

We may experience future releases of refined petroleum products into the environment from the operation of our pipeline systems, terminals and associated facilities in connection with the transportation, storage and distribution of refined petroleum products, crude oil and other liquid hydrocarbons or discover historical releases that were previously unidentified or not assessed. While we maintain an extensive asset inspection and maintenance program designed, as applicable, to prevent, detect and address these releases promptly, damages and liabilities incurred due to any future environmental releases from our assets nevertheless have the potential to substantially affect our business.

Environmental Indemnification from Williams and its Affiliates

Williams, certain of its affiliates and MMH, will indemnify us against certain environmental liabilities. Williams has guaranteed the obligations of its affiliates. The terms and limitations of these indemnification agreements are summarized below.

For assets transferred to us from Williams at the time of our initial public offering in February 2001, Williams agreed to indemnify us for up to $15.0 million for environmental liabilities that exceed the amounts covered by the indemnities we received from the sellers of those assets as described below. The indemnity applies to environmental liabilities arising from conduct prior to the closing of the initial public offering (February 9, 2001) and discovered within three years of closing of the initial public offering; however, the discovery period has been extended to August 9, 2004.

In connection with our April 2002 acquisition of Magellan Pipeline, which comprises the majority of our petroleum products pipeline system, Williams has agreed to indemnify us for losses and damages related to breaches of representations and warranties, including environmental representations and warranties and the violation or liabilities arising under any environmental laws prior to the acquisition. This indemnity covers losses in excess of $2.0 million up to a maximum of $125.0 million. Claims related to this environmental indemnity must be made prior to April 2008 and must be related to events that occurred prior to April 11, 2002.

In addition to these two agreements, the purchase and sale agreement ("June 2003 PSA") entered into in connection with Williams' sale of its interests in us provides us with two additional indemnities related to environmental liabilities.

First, MMH (the buyer under the June 2003 PSA) assumed Williams' obligations to indemnify us for $21.9 million of known environmental liabilities, of which $19.0 million was associated with known liabilities at Magellan Pipeline facilities, $2.7 million was associated with known liabilities at our petroleum products terminal facilities and $0.2 million was associated with known liabilities on the ammonia pipeline system.

Second, in the June 2003 PSA, Williams agreed to indemnify us for environmental liabilities arising prior to June 17, 2003 related to all of our facilities to the extent not already indemnified under Williams' two preexisting indemnification obligations described above. This additional indemnification includes those liabilities related to our petroleum products terminals and the ammonia pipeline system arising after the initial public offering (February 9, 2001) through June 17, 2003 and those liabilities related to Magellan Pipeline arising after our acquisition of it on April 11, 2002 through June 17, 2003. This indemnification covers environmental as well as other liabilities and is capped at $175.0 million.

A summary of the indemnities we have with Williams and the liabilities and receivables associated with these indemnities is provided in Note 17 – Commitments and Contingencies to the accompanying consolidated financial statements.

Environmental Indemnifications From Third Parties

Described below are environmental indemnifications provided by outside entities when we acquired certain of our petroleum product pipeline terminals. Most of the liabilities we assumed in those acquisitions are covered by our indemnities with Williams.

In connection with the acquisition of the Dallas terminal in December 1997, Mobil Oil Corporation retained liability for ongoing remediation activities until agency closure is granted; however, if closure has not been received by December 29, 2013, we will assume any remaining liability.

In connection with the terminal assets purchased from Amoco Oil Company ("Amoco") in January 1999, Amoco retained liability for all known remediation actions until agency closure is granted; however, if closure has not been received by January 7, 2014, we will assume any remaining liability.

In connection with the three Gulf Coast marine terminal facilities acquired from Amerada Hess Corporation ("Hess") in August 1999, Hess has obligations to conduct and pay for the clean up of certain hazardous substances known to be present or have been released prior to August 1999 and has indemnified us for claims and losses arising out of these remediation obligations. These obligations and indemnifications include:

- special cleanup actions of pre-acquisition releases of hazardous substances. This obligation is capped at a maximum of $15.0 million. Hess, however, has no liability until the aggregate amount of initial losses is in excess of a $2.5 million deductible, and then Hess is liable only for the succeeding $12.5 million in losses. If we have a liability that falls into the $2.5 million deductible, a claim will be made to Williams for indemnification if it is discovered prior to August 9, 2004. We can file notification to Hess regarding indemnified matters until July 30, 2004;
- already known and required remediation actions at the Corpus Christi, Texas and Galena Park, Texas terminal facilities, excluding the Galena Park tar plant remediation, which Williams assumed liability for in January 2002. This obligation has no cap and will remain in effect until July 30, 2014, at which time we will conduct and pay for the ongoing remediation; and
- fines and claims that may be imposed or asserted under the Superfund Law and federal Resource Conservation and Recovery Act ("RCRA") or analogous state laws relative to pre-acquisition events. This indemnity is not subject to any limit or deductible amount.

In addition to these obligations and indemnities, Hess retained liability for the performance of corrective actions associated with hydrocarbon recovery from ground water and a cooling tower at the Corpus Christi, Texas terminal and a process safety management compliance matter at the Galena Park, Texas terminal facility.

In connection with our acquisition of the New Haven, Connecticut marine terminal from Wyatt Energy, Inc., in August 2000 the seller indemnified us against liabilities related to PCB's. We assumed all other environmental liabilities.

In connection with the acquisition of our two Little Rock, Arkansas terminals in June 2001, TransMontainge Inc. retained liability for ongoing remediation activities until the site receives written completion or a closure order.

We acquired 100% ownership in 6 petroleum products terminals in the Southeast through a series of 4 transactions: (1) a 45.5% interest in the terminals was acquired from Conoco, Inc. in 1996; (2) a 23.5% interest was acquired from Conoco, Inc. in 1998; (3) a 10.0% interest was acquired from Murphy Oil USA, Inc. in 1999; and (4) a 21.0% interest was acquired from Murphy Oil USA, Inc. in 2004. Under the 1996 agreement, Conoco, Inc. retained liability for 45.5% of known environmental liabilities until agency closure is granted. Under the 1998 agreement, TOC Terminals, Inc. retained liability for 23.5% of known environmental liabilities until agency closure is granted, subject to a maximum aggregate liability of $500,000. Under the 2004 agreement, we assumed liability for 31.0% of known environmental liabilities. We have also assumed liability for all unknown environmental liabilities.

Environmental Liabilities Associated with Magellan Terminal Holdings and the Ammonia Pipeline System

The Partnership has insurance policies which provide coverage for environmental matters associated with sudden and accidental releases of petroleum products. As of December 31, 2003, we had no other site-specific environmental insurance policies. Previously existing site-specific policies were retained by Williams at the time MMH acquired Williams' interest in us in support of Williams' indemnities to us.

Under the Oil Pollution Prevention regulations, EPA regulates the requirements for Spill Prevention, Control, and Countermeasure ("SPCC") plans. Currently, we are evaluating the SPCC plans for potential deficiencies at approximately 34 of our petroleum products terminal facilities and costs associated with complying with the regulations cannot be determined at this time. However, we believe that costs incurred to correct any deficiencies associated with complying with the regulations are covered by Williams' indemnification obligations described above.

We have notified the Texas Commission on Environmental Quality regarding certain potential non-compliance issues associated with the Galena Park terminal and its various air permits. At this time, we cannot assess the materiality of these notifications; however, we believe that any corrective action(s) required and/or civil penalty assessed are covered by Williams' indemnifications obligations described above.

Environmental Liabilities Associated with the Petroleum Products Pipeline System

Potentially significant assessment, monitoring and remediation projects related to events prior to our acquisition of the petroleum products pipeline system are being performed at about 45 sites in Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota and Wisconsin. We estimate, that the total cost of performing the currently anticipated assessment, monitoring and remediation at these 45 sites over future years will be approximately $23.4 million, of which at least $20.9 million, and potentially all $23.4 million, is covered by our indemnification agreements with Williams or MMH. The most significant remedial costs at these sites are costs attributed to cleanup at eight terminals and four right-of-way locations where we estimate that $17.3 million of the $23.4 million in costs will be incurred. This estimate assumes that we will be able to use common remedial and monitoring methods or associated engineering or institutional controls to demonstrate compliance with applicable regulatory requirements. This estimate covers the cost of performing assessment, remediation and/or monitoring of impacted soils, groundwater and surface water conditions, but does not include any costs for potential claims by others with respect to these sites.

Under the Oil Pollution Prevention regulations, EPA regulates the requirements for SPCC plans. Currently we are assessing the impact of deficiencies at approximately 70 Magellan Pipeline facilities and the costs associated with complying with the regulations cannot be determined at this time. However, we believe that any costs incurred to correct any associated deficiencies to comply with the regulations are covered by Williams' indemnification obligations described above.

We are currently negotiating a consent order for Magellan Pipeline's Enid terminal. Capital costs associated with that order are estimated at approximately $2.0 million and the civil penalty associated with the alleged non-compliance with federal air regulations from December 1997 through December 2001 are estimated to be between $0.5 million and $1.5 million. We believe these costs are covered by Williams' indemnification obligations described above.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from Williams and its affiliates' pipelines, pipeline systems and pipeline facilities used in the movement of oil or petroleum products during the period from July 1, 1998 through July 2, 2001. In November 2001, Williams furnished its response, which related primarily to our petroleum products pipeline system. In September 2003, the EPA notified Williams it was reviewing Williams' response. To date, neither Williams nor we have received further correspondence from the EPA related to this issue; however, we believe any civil penalty that arises from this matter are covered by Williams' indemnification obligations described above.

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 the 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. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances. Under the Superfund law, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. The Superfund law also authorizes the EPA, and in some instances third parties, to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within the Superfund law's definition of a hazardous substance, and as a result, we may be jointly and severally liable under the Superfund law for all or part of the costs required to clean up sites at which those hazardous substances have been released into the environment.

In 2003, the EPA notified Williams that it was a potentially responsible party for two Superfund sites. Williams has responded to both EPA correspondences indicating that neither Williams nor we have any documentation or knowledge of being a potentially responsible party at either site. Responses from the EPA have not been received to date.

Our operations also generate wastes, including hazardous wastes that are subject to the requirements of the 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 from time to time will 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, will in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly storage and disposal requirements than are non-hazardous wastes. Changes in the regulations could have a material adverse effect on our capital expenditures or operating expenses.

We currently 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 clean up contaminated property, including groundwater contaminated by prior owners or operators, or to make capital improvements to prevent future contamination.

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 API 653 to regulate above ground tanks subject to their jurisdiction. We believe we are in material compliance with all applicable above ground storage tank laws and regulations. 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 financial condition or results of operations.

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 or the 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 unlimited 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 and 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 financial condition or results of operations.

The Federal 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 Federal Water Pollution Control Act or a state-delegated program, and we believe that we are in material compliance with the terms of those permits. While we have experienced permit discharge exceedences 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 financial position or results of operations.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state and local laws. Under such laws, permits are typically required to emit pollutants into the atmosphere. Amendments to the federal Clean Air Act enacted in 1990, as well as recent or soon to be proposed changes to state implementation plans ("SIPs"), for controlling air emissions in regional, non-attainment areas require or will require most industrial operations in the United States to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies. As a result of these amendments, our facilities that emit volatile organic compounds or nitrogen oxides are subject to increasingly stringent regulations, including requirements that some sources install maximum or reasonably available control technology. In addition, the amendments 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 and that we are in material compliance with applicable air laws and regulations. Although we can give no assurances, we believe implementation of the 1990 federal Clean Air Act amendments and any changes to the SIPs pertaining to air quality in regional non-attainment areas will not have a material adverse effect on our financial condition or results of operations.

Employee Safety

We are subject to the requirements of the federal OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in material compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

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 the ammonia pipeline that arise within 15 years after the closing of our initial public offering and (2) title defects related to the petroleum products pipeline system that arise within ten years from its acquisition. 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.

The assets of our petroleum products pipeline system have been pledged as collateral to secure the Series A and Series B notes issued by Magellan Pipeline (see Note 13—Debt to the accompanying consolidated financial statements for further information).

Employees

To conduct our operations, an affiliate of our general partner employs approximately 823 employees, of whom 435 conduct the operations of our petroleum products pipeline system, 174 conduct the operations of our petroleum products terminals and 214 provide general and administrative services. From June 18, 2003 through December 31, 2003, an affiliate of our general partner contracted with Williams for these services.

Approximately 216 of the employees assigned to our petroleum products pipeline system are represented by the Paper, Allied-Industrial, Chemical and Energy Workers International Union ("PACE"). The employees represented by PACE are subject to a contract that extends through January 2006. None of the terminal operations employees are represented by a union. The employees at our Galena Park marine terminal facility were previously represented by a union, but indicated in 2000 their unanimous desire to terminate their union affiliation. Nevertheless, the National Labor Relations Board ("NLRB") ordered us to bargain with the union as the exclusive collective bargaining representative of the employees at the facility. Subsequently, the NLRB reversed its decision and withdrew its order. Our general partner's affiliate considers its employee relations to be good.

(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 other reports and other information electronically with the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, 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 (http://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.

Our Internet address is www.magellanlp.com. We make available, free of charge on or through our Internet website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Our Corporate Governance Guidelines, Audit Committee charter, Compensation Committee charters and Code of Business Conduct, each of which has been approved by our general partner's board of directors, are available on our website at www.magellanlp.com. Our unitholders may request a written copy of these materials by calling 1-918-574-7000.

ITEM 2. *Properties*

See Item 1(c) for a description of the locations and general character of our material properties.

ITEM 3. *Legal Proceedings*

In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act, preliminarily determined that Magellan Pipeline may have systematic problems with discharges from its pipelines and served Williams with an information request. In November 2001, Williams submitted a timely response to the EPA information request. In September 2003, the EPA notified Williams that it was reviewing its response. No further communications have been received from the EPA regarding this matter. If the EPA determines that Magellan Pipeline has systematic problems with discharges from its pipelines, it may result in a fine in excess of $100,000. We believe any fine the EPA may assess in this matter is covered by Williams' indemnity obligations.

The Oklahoma Department of Environmental Quality ("ODEQ") alleges in two separate Notice of Violations dated June 14, 2002 and September 30, 2003 that a terminal on our petroleum products pipeline system located in Enid, Oklahoma violated its air permit and applicable regulations by non-compliance with the federal Maximum Achievable Control Technology ("MACT") standards, which the ODEQ alleges are applicable to the facility. This proceeding is in the preliminary stages. However, if the ODEQ determines that the terminal is subject to the MACT standards, it may result in a monetary fee in excess of $100,000. We believe that any monetary fees and any cost to bring the terminal into compliance with the MACT standards are covered by Williams' indemnity obligation.

On August 8, 2003, we notified the Texas Commission on Environmental Quality ("TCEQ") that we were requesting immunity from civil and administrative penalties under the Texas Environmental Health and Safety Audit Privilege Act ("Audit Act") for potential violations of TCEQ rules, federal rules or permit emission limits arising out of air emissions produced when storage tank floating roofs are landed on their support legs when tanks are emptied. To qualify for immunity under the Audit Act, the violation must have been noted and disclosed as a result of a voluntary environmental audit and must meet the reasonable inquiry standard required under the EPA Clean Air Act Title V regulations. If the TCEQ concludes that our environmental audit that led to the disclosure to TCEQ did not exceed the reasonable inquiry standard, the immunity provided by the Audit Act would not apply, which may result in a fine in excess of $100,000. We believe that any fine the TCEQ may assess in this matter is covered by Williams' indemnity obligations.

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***

Our Annual Meeting of Limited Partners was held on November 7 and 21, 2003. At this meeting, two individuals were elected as directors of our general partner's board of directors and the conversion of each outstanding class B common unit into one common unit, and the resulting issuance of an aggregate of 7,830,924 common units upon the conversion and cancellation of the 7,830,924 class B common units was approved.

A tabulation of the voting with respect to each of the matters voted upon at the meeting follows:

Election of Directors

Name	For	Withheld	Abstain	Broker Non-Votes
Justin S. Huscher	14,676,245	776,222	—	—
David M. Leuschen	14,680,065	772,402	—	—

Conversion of Class B Common Units into Common Units

For	Against	Abstain	Broker Non-Votes
7,320,005	78,831	45,365	5,777,973

PART II

ITEM 5. ***Market For Registrant's Common Equity and Related Stockholder Matters***

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". Subsequent to our name change to Magellan Midstream Partners, L.P. on September 1, 2003, our common units are listed on the New York Stock Exchange under the ticker symbol "MMP". At the close of business on March 1, 2004, we had 143 registered holders and 24,790 beneficial holders of record of our common units. The high and low closing sales price ranges and distributions paid by quarter for 2001, 2002 and 2003 are as follows:

	2001			2002			2003		
Quarter	High	Low	Distribution*	High	Low	Distribution*	High	Low	Distribution*
1st	$31.00	$24.00	$.2920	$43.30	$32.85	$.6125	$37.19	$33.30	$.7500
2nd	$33.42	$28.45	$.5625	$42.35	$30.75	$.6750	$48.20	$37.54	$.7800
3rd	$40.40	$29.40	$.5775	$36.40	$25.20	$.7000	$48.55	$42.40	$.8100
4th	$44.00	$37.00	$.5900	$34.70	$29.50	$.7250	$55.03	$45.80	$.8300

* Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter. The distribution for the first quarter of 2001 was pro-rated for the period from February 10, 2001 through March 31, 2001 due to the timing of our initial public offering.

In addition to common units, we also issued 5,679,694 subordinated units as part of our initial public offering in February 2001. There is no established public trading market for these units. All of the subordinated units are held by an affiliate of our general partner and receive a quarterly distribution only after sufficient funds have been paid to the common units, as described below. In addition, the subordinated units generally have reduced voting rights equal to one-half vote for each unit owned.

Prior to November 2003, we also had 7,830,924 class B common units outstanding, which were all held by an affiliate of our general partner. These units were issued as partial payment for the April 2002 purchase of our petroleum products pipeline system (see Note 6—Acquisitions and Divestitures in the accompanying consolidated financial statements for additional information on this acquisition). These units were equivalent to common units except they only had voting rights with respect to matters that would have a material impact on the holders of such units. The holder of the class B common units had the right to request conversion of these units into common units on a 1-for-1 basis beginning April 2003. The holder did request that the common unitholders vote to approve the conversion of the class B common units and such approval was granted at the annual meeting of limited partners held during November 2003. These units have converted to common units and are no longer outstanding.

During the subordination period, the holders of our common units are entitled to receive each quarter a minimum quarterly distribution of $0.525 per unit ($2.10 annualized) prior to any distribution of available cash to holders of our subordinated units. The subordination period is defined generally as the period that will end on the first day of any quarter beginning after December 31, 2005 if (1) we have distributed at least the minimum quarterly distribution on all outstanding units with respect to each of the immediately preceding three consecutive, non-overlapping four-quarter periods and (2) our adjusted operating surplus, during such periods, as defined in our partnership agreement, equals or exceeds the amount that would have been sufficient to enable us to distribute the minimum quarterly distribution on all outstanding units on a fully diluted basis and the related distribution on the 2% general partner interest during those periods. In addition, one-quarter of the subordinated units may convert to common units on a one-for-one basis after December 31, 2003 and one-quarter of the subordinated units may convert to common units on a one-for-one basis after December 31, 2004 if we meet the tests set forth in our partnership agreement. If the subordination period ends, the rights of the holders of subordinated units will no longer be subordinated to the rights of the holders of common units and the subordinated units may be converted into common units. We met the first early conversion test effective February 2004, and 25%, or 1,419,923, of our 5,679,694 then outstanding subordinated units converted to common units. The impact of this conversion is that the existing common units have less subordinated protection with respect to distributions and the subordinated units that converted into common units received voting rights equivalent to those of the common units.

During the subordination period, our cash is distributed first 98% to the holders of common units and 2% to our general partner until there has been distributed to the holders of common units an amount equal to the minimum quarterly distribution and arrearages in the payment of the minimum quarterly distribution on the common units for any prior quarter. Any additional cash is distributed 98% to the holders of subordinated units and 2% to our general partner until there has been distributed to the holders of subordinated units an amount equal to the minimum quarterly distribution.

Our general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Percentage of Distributions	
Quarterly Distribution Amount per Unit	**Limited Partners**	**General Partner**
Up to $.578	98	2
Above $.578 up to $.656	85	15
Above $.656 up to $.788	75	25
Above $.788	50	50

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 $0.83 per unit, which entitles our general partner to receive approximately 12% of the total cash distributions paid. In general, we intend to continue to increase 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.

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, which comprises the majority of our petroleum products pipeline system, 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.

The historical results for Magellan Pipeline included income and expenses and assets and liabilities that were conveyed to and assumed by an affiliate of Magellan Pipeline prior to our acquisition of it. The assets principally included Magellan Pipeline's interest in and agreement related to Longhorn Partners Pipeline, L.P. ("Longhorn"), an inactive refinery site at Augusta, Kansas, a pipeline construction project, the ATLAS 2000 software system and the pension asset and obligations associated with the non-contributory defined-benefit pension plan that covered employees assigned to Magellan Pipeline's operations. The liabilities principally included the environmental liabilities associated with an inactive refinery site in Augusta, Kansas and current and deferred income taxes and affiliate note payable. The current and deferred income taxes and the affiliate note payable were contributed to us in the form of a capital contribution by an affiliate of Williams. Also, as agreed between the Partnership and Williams, operating results from Magellan Pipeline's petroleum products management operation, other than an annual fee of approximately $4.0 million, were not included in the financial results of the Partnership since April 2002. In addition, general and administrative expenses related to the petroleum products pipeline system for which the Partnership had been reimbursing its general partner, were limited to $30.7 million on an annual basis. This cap was increased to $31.0 million on February 1, 2003 when Magellan Pipeline began operating the Rio Grande Pipeline. The ATLAS 2000 software system assets were contributed to the Partnership on June 17, 2003 in conjunction with the sale by Williams of its interests in the Partnership (see *Change in Ownership of General Partner* under Note 1—Organization and Presentation in the accompanying consolidated financial statements), and the depreciation expense associated with those assets has been included in the Partnership's results since that date. Also, the Partnership acquired Williams' interest in the petroleum products management operation in July 2003 (see Note 6—Acquisitions and Divestitures in the accompanying consolidated financial statements), and the results of this operation have been included in the Partnership's results subsequent to that date.

EBITDA, a non-generally accepted accounting principle measure presented in the following schedules, is defined as net income plus provision for income taxes, 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 income, cash flow from operations or any other measure of financial performance presented in accordance with generally accepted accounting principles ("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. 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 table (see Note 16—Segment Disclosures in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit). The Partnership believes that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important performance measure of the economic success of the Partnership's core operations. This measure forms the basis of the Partnership's internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items that management does not consider when evaluating the core profitability of an operation such as depreciation and general and administrative costs.

	Year Ended December 31,				
	1999	2000	2001	2002	2003
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$287,107	$ 318,121	$ 339,412	$ 363,740	$ 372,848
Product sales revenues	70,750	106,873	108,169	70,527	112,312
Affiliate construction and management fee revenues	17,875	1,852	1,018	210	—
Total revenues	375,732	426,846	448,599	434,477	485,160
Operating expenses including environmental expenses net of indemnifications	121,599	144,899	160,880	155,146	166,883
Product purchases	59,230	94,141	95,268	63,982	99,907
Affiliate construction expenses	15,464	1,025	—	—	—
Operating margin	179,439	186,781	192,451	215,349	218,370
Depreciation and amortization	25,670	31,746	35,767	35,096	36,081
General and administrative	47,062	51,206	47,365	43,182	56,846
Total costs and expenses	269,025	323,017	339,280	297,406	359,717
Operating profit	106,707	103,829	109,319	137,071	125,443
Interest expense, net	18,998	25,329	12,113	21,758	34,536
Debt placement fees	—	—	253	9,950	2,830
Other (income) expense, net	(1,511)	(816)	(431)	(2,112)	(92)
Income before income taxes	89,220	79,316	97,384	107,475	88,169
Provision for income taxes[a]	34,121	30,414	29,512	8,322	—
Net income	$ 55,099	$ 48,902	$ 67,872	$ 99,153	$ 88,169
Basic net income per limited partner unit			$ 1.87	$ 3.68	$ 3.32
Diluted net income per limited partner unit			$ 1.87	$ 3.67	$ 3.31
Balance Sheet Data:					
Working capital (deficit)	$ (2,115)	$ 17,828	$ (2,211)	$ 47,328	$ 77,438
Net investment in direct financing leases	3,143	2,770	11,046	10,231	9,230
Total assets	973,939	1,050,159	1,104,559	1,120,359	1,194,624
Long-term debt	—	—	139,500	570,000	569,100
Affiliate long-term note payable[b]	406,022	432,957	138,172	—	—
Partners' capital	339,601	388,503	589,682	451,757	498,149
Cash Flow Data:					
Cash distributions declared per unit[c]			$ 2.02	$ 2.71	$ 3.17
Cash distributions paid per unit[c]			$ 1.43	$ 2.58	$ 3.07

	Year Ended December 31,				
	1999	2000	2001	2002	2003
	(in thousands, except per unit amounts)				
Other Data:					
Operating margin:					
Petroleum products pipeline system	$153,686	$147,778	$143,711	$163,233	$162,494
Petroleum products terminals	17,141	31,286	38,240	43,844	46,909
Ammonia pipeline system	8,612	7,717	10,500	8,272	8,094
Allocated partnership depreciation costs[d]	—	—	—	—	873
Operating margin	$179,439	$186,781	$192,451	$215,349	$218,370
EBITDA:					
Net income	$ 55,099	$ 48,902	$ 67,872	$ 99,153	$ 88,169
Income taxes[a]	34,121	30,414	29,512	8,322	—
Amortization of debt placement fees	—	—	253	9,950	2,830
Interest expense, net	18,998	25,329	12,113	21,758	34,536
Depreciation and amortization	25,670	31,746	35,767	35,096	36,081
EBITDA	$133,888	$136,391	$145,517	$174,279	$161,616

	Year Ended December 31,				
	1999	2000	2001	2002	2003
Operating Statistics:					
Petroleum products pipeline system:					
Transportation revenue per barrel shipped (cents per barrel)	91.4	89.1	90.8	94.9	96.4
Transportation barrels shipped (millions)	222.5	229.1	236.1	234.6	237.6
Barrel miles (billions)	67.8	68.2	70.5	71.0	70.5
Petroleum products terminals:					
Marine terminal average storage capacity utilized per month (million barrels)[e]	10.1	14.7	15.7	16.2	15.2
Marine terminal throughput (million barrels)[f]	N/A	3.7	11.5	20.5	22.2
Inland terminal throughput (million barrels)	58.1	56.1	56.7	57.3	61.2
Ammonia pipeline system:					
Volume shipped (thousand tons)	795	713	763	712	614

(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 an affiliate of Williams. At the closing of our acquisition of Magellan Pipeline, its affiliate note payable was also contributed to us as a capital contribution by an affiliate of Williams.

(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 the Partnership 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 of the Partnership was recorded at the segment level. The associated depreciation expense was charged to the Partnership's various business segments which, in turn, recognized these allocated costs as operating expense. Consequently, the segment's individual operating margins were reduced by these costs.

(e) For the year ended December 31, 1999, represents the average storage capacity utilized per month for the Gulf Coast marine terminal facilities for the five months that we owned these assets in 1999. For the year ended December 31, 2000, represents the average monthly storage capacity utilized for the Gulf Coast facilities (11.8 million barrels) and the average monthly storage capacity utilized for the four months that we owned the New Haven marine terminal facility in 2000 (2.9 million barrels). All of the above amounts exclude the Gibson facility, which is operated as a throughput facility.

(f) For the year ended December 31, 2000, represents four months of activity at the New Haven facility, which was acquired in September 2000. For the year ended December 31, 2001, represents a full year of activity for the New Haven facility (9.3 million barrels) and two months of activity at the Gibson facility (2.2 million barrels), which was acquired in October 2001.

ITEM 7.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the consolidated financial statements and notes thereto. Magellan Midstream Partners, L.P., formerly Williams Energy Partners L.P., is 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 current asset portfolio consists of:

- A 6,700-mile refined petroleum products pipeline system with 39 terminals;
- five marine terminal facilities;
- 29 inland terminals (six of which were acquired during January 2004 as discussed in *Recent Developments* below); and
- an 1,100-mile ammonia pipeline system.

During April 2002, we acquired Magellan Pipeline Company, LLC ("Magellan Pipeline"), which comprises the majority of our petroleum products pipeline system, for approximately $1.0 billion from a wholly owned subsidiary of The Williams Companies, Inc. ("Williams"). Because Williams was an affiliate of ours at the time of the acquisition, the transaction was between entities under common control and, as such, was accounted for similar to a pooling of interest. Accordingly, our consolidated financial statements and notes have been restated to reflect the historical results of operations, financial position and cash flows of this pipeline system and us on a combined basis throughout the periods presented.

Significant Events

On June 17, 2003, Williams sold its 54.6% interest in us to Magellan Midstream Holdings, L.P. ("MMH"), a new entity jointly formed by private equity firms Madison Dearborn Capital Partners IV, LLC and Carlyle/Riverstone MLP Holdings, L.P. MMH acquired 1.1 million of our common units, 5.7 million subordinated units, 7.8 million class B common units and 100% of the ownership interest in our general partner.

The change in majority ownership of this transaction resulted in the following items, primarily due to our separation from Williams:

- effective September 1, 2003, we began doing business as Magellan Midstream Partners, L.P. and changed our New York Stock Exchange ticker symbol to "MMP";

- based on previous agreements between Williams and us, Williams had responsibility for providing our general and administrative ("G&A") services, which included functions such as commercial operations, engineering, information technology, finance, accounting, human resources and other corporate services. We paid a specified cash cost for these services, excluding expenses associated with our equity-based incentive plans, with the capped amount escalating annually. Williams was responsible for paying any cost related to these services in excess of the amount we paid to them. As a result of the sale of Williams' interests in us, these agreements with Williams terminated. MMH agreed to continue providing G&A services to us and we incur the same cash cost, which was equivalent to $38.2 million on an annual basis at December 31, 2003, excluding expenses associated with our equity-based incentive plans. MMH will reimburse us for amounts that exceed the cap. The cap will escalate at 7.0% annually and will further increase for incremental G&A costs associated with acquisitions we complete;
- under the new organization structure put in place after MMH's acquisition of us, we can now clearly identify all G&A costs required to support ourselves. Actual cash G&A costs incurred by us will continue to be limited to the G&A cap and the amount of costs above the cap that MMH must pay will be recorded as a capital contribution by our general partner. We recorded expense of approximately $5.9 million for the period June 18, 2003 to December 31, 2003 related to the reimbursable G&A. The reimbursable G&A expense will not impact earnings per unit for the limited partners as the costs above the cap are allocated entirely to our general partner's net income. In addition, the reimbursable G&A expense will not impact cash available for distribution as these costs are reimbursed to us by our affiliate;
- we recorded a $5.5 million affiliate liability during 2003 for paid-time off benefits associated with employees supporting us. Prior to June 17, 2003, this liability had been recorded on the balance sheet of Williams. The corresponding expenses did not impact cash available for distribution in 2003;
- as part of our separation from Williams, we paid for $5.0 million of transition costs primarily to establish our own G&A functions and change our name. In addition, we incurred $0.9 million of preparatory costs associated with the transition and upgrade related to our financial accounting systems. Therefore, we were responsible for funding $5.9 million of the transition costs with any incremental transition costs above this amount recorded as a capital contribution by our general partner. During 2003, transition costs totaled $8.7 million. We recorded $3.7 million of this amount as expense and $5.0 million to property, plant and equipment. The costs in excess of $5.9 million will not impact cash available for distributions or earnings per unit for the limited partners as the costs above our $5.9 million responsibility is allocable entirely to our general partner. We expect to incur approximately $1.7 million of transition costs during 2004; and
- MMH assumed $21.9 million of the environmental indemnifications from Williams associated with known environmental liabilities as of March 31, 2003. Therefore, amounts recorded in our financial statements associated with these known liabilities are now indemnified by MMH. We will seek reimbursement from Williams for other environmental liabilities and environmental capital expenditures in excess of this amount that qualify for reimbursement.

In late December 2003, MMH sold 4,300,000 common units and we sold 200,000 common units in an underwritten public offering. MMH sold an additional 675,000 common units in January 2004, when the underwriters exercised their over-allotment option. The net proceeds from our sale of the 200,000 units, after transaction costs and underwriting commissions, were $9.5 million. We also received a $0.2 million contribution from MMH to maintain its 2% general partner interest. Proceeds from these transactions will be used for general partnership purposes. Following these transactions, MMH has an approximate 36% ownership interest in us, including its 2% general partner interest.

Recent Developments

On January 27, 2004, the board of directors of our general partner declared a quarterly cash distribution of $0.83 per unit for the period of October 1 through December 31, 2003. The fourth-quarter distribution represents a 14% increase over the fourth-quarter 2002 distribution of $0.725 per unit and a 58% increase since our initial public offering in February 2001. The distribution was paid on February 13, 2004 to unitholders of record on February 6, 2004.

On January 29, 2004, we announced our acquisition of ownership interests in 14 inland terminals located in the southeastern United States for $24.8 million. We previously owned a 79% interest in eight of these terminals and acquired the remaining 21% ownership interest in these eight terminals from Murphy Oil USA, Inc. In addition, we acquired sole ownership of six terminals that had been jointly owned by Murphy Oil USA, Inc. and Colonial Pipeline Company.

In February 2004, we entered into three separate agreements with two different banks for forward starting interest rate swaps totaling $150.0 million. The swaps begin in October 2007, when we expect to refinance the majority of Magellan Pipeline's $480.0 million senior secured notes. Under the swap agreements, we will pay fixed interest rates and will receive LIBOR for a ten-year period, which is the assumed tenure of replacement debt. The average fixed rate on the swaps is 5.9%.

On March 2, 2004, we acquired a 50% ownership in Osage Pipe Line Company, LLC, which owns the Osage Pipeline, for $25.0 million from National Cooperative Refinery Association ("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. The remaining 50% interest in the Osage Pipe Line Company, LLC will continue to be owned by NCRA.

Overview

In 2003, our cash flow significantly exceeded our debt service obligations and cash distributions to our unitholders. Our petroleum products pipeline system generates a substantial portion of this cash flow. The revenues generated from the petroleum products pipeline business are significantly influenced by demand for refined petroleum products, which has been growing in the markets we serve. In addition, expenses for this business are principally fixed and relate to routine maintenance and system integrity work as well as field and support personnel cost.

We expect to maintain or grow the cash flow of the petroleum products pipeline system as well as our other businesses in the future. However, a prolonged period of high refined-product prices could lead to a reduction in demand and result in lower shipments on our pipeline system. In addition, increased pipeline maintenance regulations, higher power costs and higher interest rates could decrease the amount of cash we generate.

Petroleum Products Pipeline System. Our petroleum products pipeline system is a common carrier transportation pipeline and terminals network. The system 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 transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission ("FERC"). The petroleum products pipeline system 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.

Our petroleum products pipeline system generally does not produce, trade or take title to the products it transports. However, the system does generate small volumes of product through its fractionation activities.

In July 2003, we purchased a petroleum products management operation from Williams and we now take title to the associated inventories and resulting products. From April 2002 through June 2003, we did not purchase and take title to the inventories or resulting products associated with this operation but performed services related to this operation for an annual fee of approximately $4 million. We also purchase and fractionate transmix and sell the resulting separated products.

Operating costs and expenses incurred by the petroleum products pipeline system 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 and stored on the system. Expenses resulting from environmental remediation projects have historically included costs from projects relating both to current and past events. In connection with our acquisition of this pipeline system, an affiliate of Williams agreed to indemnify us for costs and expenses relating to environmental remediation for events that occurred before April 11, 2002 and are discovered within six years from that date. See "Business—Environmental" under Item 1 of this 10-K report.

Petroleum Products Terminals. Within our terminals network, we operate two types of terminals: marine terminal facilities and inland terminals. The marine terminal facilities are large product storage facilities that generate revenues primarily from fees that we charge customers for storage and throughput services. The inland terminals earn revenues primarily from fees we charge based on the volumes of refined petroleum products distributed from these terminals. The inland terminals also earn ancillary revenues from injecting additives into gasoline and jet fuel and filtering jet fuel.

Operating costs and expenses that we incur in our marine and inland terminals are principally fixed costs related to routine maintenance as well as field and support personnel. Other costs, including power, fluctuate with storage utilization or throughput levels.

Ammonia Pipeline System. The ammonia pipeline system earns the majority of its revenue from transportation tariffs that we charge for transporting ammonia through the pipeline. 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 routine maintenance as well as field personnel. Other costs, including power, fluctuate with volumes transported on the pipeline.

Acquisition History

We have increased our operations through a series of acquisitions:

- in March 2004, the acquisition of a 50% ownership interest in Osage Pipeline;
- 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 the petroleum products management business from a subsidiary of Williams;
- in April 2002, the acquisition of the 6,700-mile petroleum products pipeline system from a subsidiary of Williams;
- in December 2001, the acquisition of a natural gas liquids pipeline in Illinois from Aux Sable Liquid Products L.P.;
- in October 2001, the acquisition of a marine crude oil terminal facility in Gibson, Louisiana from Geonet Gathering, Inc.;
- in June 2001, the acquisition of two inland refined petroleum products terminals in Little Rock, Arkansas from TransMontaigne, Inc.; and
- in April 2001, the acquisition of a refined petroleum products pipeline in Dallas, Texas from Equilon Pipeline Company LLC, which is part of our petroleum products terminals segment;

Results of Operations

The non-generally accepted accounting principle ("GAAP") financial measure of operating margin is presented below. 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 table below.

We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important performance measure of the economic success 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 profit, alternatively, includes expense items that management does not consider when evaluating the core profitability of an operation such as depreciation and G&A costs.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2003

	Year Ended December 31,	
	2002	**2003**
Financial Highlights (in millions)		
Revenues:		
Transportation and terminals revenue:		
Petroleum products pipeline system	$272.5	$281.4
Petroleum products terminals	78.1	78.9
Ammonia pipeline system	13.1	12.6
Total transportation and terminals revenue	363.7	372.9
Product sales	70.6	112.3
Affiliate management fees	0.2	—
Total revenues	434.5	485.2
Operating expenses, environmental expenses and environmental reimbursements:		
Petroleum products pipeline system	114.7	128.5
Petroleum products terminals	35.5	34.7
Ammonia pipeline system	4.9	4.5
Eliminations	—	(0.8)
Total operating expenses, environmental expenses and environmental reimbursements	155.1	166.9
Product purchases	64.0	99.9
Operating margin	215.4	218.4
Depreciation and amortization	35.1	36.1
Affiliate general and administrative expenses	43.2	56.9
Operating profit	$137.1	$125.4
Operating Statistics		
Petroleum products pipeline system:		
Transportation revenue per barrel shipped (cents per barrel)	94.9	96.4
Transportation barrels shipped (million barrels)	234.6	237.6
Barrel miles (billions)	71.0	70.5
Petroleum products terminals:		
Marine terminal facilities:		
Average storage capacity utilized per month (barrels in millions)	16.2	15.2
Throughput (barrels in millions)	20.5	22.2
Inland terminals:		
Throughput (barrels in millions)	57.3	61.2
Ammonia pipeline system:		
Volume shipped (tons in thousands)	712	614

Transportation and terminals revenues for the year ended December 31, 2003 were $372.9 million compared to $363.7 million for the year ended December 31, 2002, an increase of $9.2 million, or 3%. This increase was a result of:

- an increase in petroleum products pipeline system revenues of $8.9 million, or 3%, primarily attributable to a higher weighted-average tariff and increased volumes during the current period. The higher transportation rates per barrel principally resulted from tariff increases during July 2002 and April 2003. Tariff adjustments generally occur during July of each year, as allowed by the FERC. However, the April 2003 increase was allowed by the FERC due to a change to the mid-year FERC-defined tariff calculation. The incremental volume resulted from the short-term refinery production decreases in the mid-continent region of the U.S. These production decreases resulted in substitute volumes from alternative sources moving through our pipeline system. Further, increased revenues from higher data service fees as well as greater capacity lease utilization and other ancillary revenues benefited the current year;
- an increase in petroleum products terminals revenues of $0.8 million, or 1%, primarily due to increased throughput at our inland terminals as volumes of a former affiliate were more than replaced with higher volumes from third-party customers. Utilization at the Gulf Coast marine facilities was lower between the two periods due to the termination of a former affiliate's storage agreement at our Galena Park, Texas facility during the first quarter of 2003. Increased revenues from the $3.0 million settlement we received were more than offset by the resulting reduced storage utilization; and
- a decrease in ammonia pipeline system revenues of $0.5 million, or 4%, primarily due to significantly reduced transportation volumes during the first quarter of 2003 resulting from extremely high prices for natural gas, the primary component in the production of ammonia. Partially offsetting this volume decline was a higher weighted-average tariff in 2003.

Operating expenses, environmental expenses and environmental reimbursements combined were $166.9 million for the year ended December 31, 2003 compared to $155.1 million for the year ended December 31, 2002, an increase of $11.8 million, or 8%. Of this increase, $3.4 million was associated with the affiliate paid-time off benefits liability associated with operations employees and was recorded in conjunction with the change in ownership of our general partner. By business segment, this increase was the result of:

- an increase in petroleum products pipeline system expenses of $13.8 million, or 12%, in part due to a $2.6 million affiliate paid-time off benefits accrual. Operating expenses further increased due to the retirement of assets and increased costs for tank maintenance and pipeline testing associated with the ongoing implementation of our system integrity program. Increased power costs resulting from higher transportation volumes and power rates as well as higher ad valorem taxes also resulted in greater costs during 2003;
- a decrease in petroleum products terminals expenses of $0.8 million, or 2%, primarily due to reduced maintenance expenses resulting from efficiency projects that lowered contract labor and repair costs. Timing of tank inspection and cleaning further resulted in reduced maintenance expenses during 2003. These positive variances were partially offset by a charge associated with the retirement of an asset, a $0.8 million affiliate paid-time off benefits accrual and increased ad valorem taxes; and
- a decrease in ammonia pipeline system expenses of $0.4 million, or 8%, primarily due to the purchase in 2002 of right-of-way easements that have historically been leased.

Revenues from product sales were $112.3 million for the year ended December 31, 2003, while product purchases were $99.9 million, resulting in a net margin of $12.4 million in 2003. The 2003 net margin represents an increase of $5.8 million compared to a net margin in 2002 of $6.6 million resulting from product sales for the year ended December 31, 2002 of $70.6 million and product purchases of $64.0 million. The increase in 2003 primarily reflects the margin results from our acquisition of the petroleum products management operation during July 2003. From April 2002 through June 2003, we provided services related to this operation for an affiliate of Williams for an annual fee rather than generating a commodity margin.

Depreciation and amortization expense for the year ended December 31, 2003 was $36.1 million, representing a $1.0 million increase from 2002 at $35.1 million due to the additional depreciation associated with acquisitions and capital improvements.

G&A expenses for the year ended December 31, 2003 were $56.9 million compared to $43.2 million for the year ended December 31, 2002, an increase of $13.7 million, or 32%.

- $7.4 million of this increase was associated with one-time costs resulting from the change in ownership of our general partner during 2003 as follows:
  - $3.7 million was associated with the separation of our G&A functions from Williams, which primarily included the creation of our information technology systems and benefits programs;
  - $2.1 million was related to recording an affiliate paid-time off benefits liability associated with G&A employees; and
  - $1.6 million was associated with the early vesting of units granted under our 2001 and 2002 equity-based incentive compensation plan resulting from the change in control of our general partner.
- $5.9 million was associated with G&A costs in excess of the G&A cap that will be reimbursed by MMH. As described above in *Significant Events*, as a result of the change in our organizational structure we are now able to clearly identify all G&A costs required to support ourselves and total G&A costs, including those costs above the cap amount that will be reimbursed by MMH, are recorded as our expense. Under the previous structure, we were unable to identify specific costs required to support our operations; consequently, we recorded as expense only the G&A costs under the cap, which reflected our actual cash cost. The actual cash G&A costs we incur will continue to be limited to the G&A cap and the amount of costs above the cap will be recorded as a capital contribution by our general partner.

Net interest expense for the year ended December 31, 2003 was $34.5 million compared to $21.8 million for the year ended December 31, 2002. The increase in interest expense was primarily related to the replacement during the fourth quarter of 2002 of short-term debt financing associated with the acquisition of our petroleum products pipeline system with long-term debt at higher interest rates. The weighted-average interest rate on our borrowings increased from 4.3% in 2002 to 6.3% in 2003 with the average debt outstanding increasing from $463.9 million in 2002 to $570.0 million in 2003.

Debt placement fee amortization declined from $9.9 million in 2002 to $2.8 million in 2003. During the 2002 period, the short-term debt associated with our acquisition of the petroleum products pipeline system was outstanding with related debt costs amortized over the 7-month period that the debt was outstanding. Our subsequent long-term debt financing costs are amortized over the 5-year life of the notes.

We do not pay income taxes because we are a partnership. However, earnings from the petroleum products pipeline system were subject to income taxes prior to our acquisition of it in April 2002. Taxes on these earnings were at income tax rates of 37% for the year ended December 31, 2002, based on the effective income tax rate for Williams as a result of Williams' tax-sharing arrangement with its subsidiaries. The effective income tax rate exceeds the U.S. federal statutory income tax rate primarily due to state income taxes.

Net income for the year ended December 31, 2003 was $88.2 million compared to $99.2 million for the year ended December 31, 2002, a decrease of $11.0 million, or 11%, primarily due to $10.8 million of one-time costs associated with the 2003 change in ownership of our general partner, of which $3.4 million was operating expense and $7.4 was G&A expense. Our net income further declined due to an additional $5.9 million of reimbursable G&A costs. Our operating margin increased by $3.0 million over the prior year despite the $3.4 million of one-time operating expense items, largely as a result of increased transportation volumes and rates on our petroleum products pipeline system, increased product margin associated with the purchase of our petroleum products management operation in July 2003 and reduced operating expenses associated with the petroleum products terminals. Depreciation and net interest expense increased by $1.0 million and $12.7 million, respectively, while debt placement fee amortization expense decreased $7.1 million. Other income declined $2.0 million primarily due to a gain on the sale of assets during 2002. Income taxes decreased $8.3 million due to our partnership structure.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2002

	Year Ended December 31,	
	2001	**2002**
Financial Highlights (in millions)		
Revenues:		
Transportation and terminals revenue:		
Petroleum products pipeline system	$254.9	$272.5
Petroleum products terminals	70.0	78.1
Ammonia pipeline system	14.5	13.1
Total transportation and terminals revenue	339.4	363.7
Product sales	108.2	70.6
Affiliate management fees	1.0	0.2
Total revenues	448.6	434.5
Operating expenses, environmental expenses and environmental reimbursements:		
Petroleum products pipeline system	123.6	114.7
Petroleum products terminals	33.3	35.5
Ammonia pipeline system	4.0	4.9
Total operating expenses, environmental expenses and environmental reimbursements.	160.9	155.1
Product purchases	95.3	64.0
Operating margin	192.4	215.4
Depreciation and amortization	35.8	35.1
Affiliate general and administrative expense	47.3	43.2
Operating profit	$109.3	$137.1
Operating Statistics		
Petroleum products pipeline system:		
Transportation revenue per barrel shipped (cents per barrel)	90.8	94.9
Transportation barrels shipped (million barrels)	236.1	234.6
Barrel miles (billions)	70.5	71.0
Petroleum products terminals:		
Marine terminal facilities:		
Average storage capacity utilized per month (barrels in millions)	15.7	16.2
Throughput (barrels in millions)	11.5	20.5
Inland terminals:		
Throughput (barrels in millions)	56.7	57.3
Ammonia pipeline system:		
Volume shipped (tons in thousands)	763	712

Transportation and terminals revenues for the year ended December 31, 2002 were $363.7 million compared to $339.4 million for the year ended December 31, 2001, an increase of $24.3 million, or 7%. This increase was the result of:

- an increase in petroleum products pipeline system revenues of $17.6 million, or 7%. Transportation revenues increased between periods due to higher weighted-average tariffs that more than offset slightly lower shipments. The tariffs were higher due to a mid-year rate increase and our customers' transporting products longer distances. These longer hauls resulted primarily from supply shifts within our pipeline system during the latter part of 2002 caused by temporary reductions of refinery production on our system. Further, increased rates for data services as well as higher ethanol loading and storage volumes resulted in additional revenue;

- an increase in petroleum products terminals revenues of $8.1 million, or 12%, primarily due to the acquisitions of our Gibson marine terminal facility in October 2001 and two Little Rock inland terminals in June 2001. An improved marketing environment resulted in higher utilization and rates at our Gulf Coast facilities, further increasing revenues during 2002; and
- a decrease in ammonia pipeline system revenues of $1.4 million, or 10%, primarily due to a throughput deficiency billing in the prior year that resulted from a shipper's inability to meet its minimum annual throughput commitment for the contract year ended June 2001. In addition, revenue also declined due to significantly reduced volumes from one of our shippers following its filing for Chapter 11 bankruptcy during May 2002. Partially offsetting these decreases was a higher weighted-average tariff in 2002.

Operating expenses, environmental expenses and environmental reimbursements combined were $155.1 million for the year ended December 31, 2002, compared to $160.9 million for the year ended December 31, 2001, a decrease of $5.8 million, or 4%. This decrease was the result of:

- a decrease in petroleum products pipeline system expenses of $8.9 million, or 7%, primarily due to lower environmental and maintenance expenses and reduced power costs. Environmental costs were lower due to the indemnification from an affiliate of Williams for environmental issues resulting from operations prior to our ownership of the pipeline. Maintenance expenses declined due to improved cost controls as a result of the implementation of improved operating practices. Reduced power costs resulted from lower volumes transported coupled with reduced power rates. Partially offsetting these reductions was an increase in pipeline lease expenses, which represent tariffs paid on connecting pipelines to move a customer's product to its ultimate destination;
- an increase in petroleum products terminals expenses of $2.2 million, or 7%, primarily due to the addition of the Gibson marine facility and the Little Rock inland terminals and increased maintenance expenses resulting from timing of tank cleaning and inspections at the inland terminals; and
- an increase in ammonia pipeline system expenses of $0.9 million, or 23%, primarily due to the purchase in the current year of right-of-way easements that have historically been leased and higher property taxes.

Revenues from product sales were $70.6 million for the year ended December 31, 2002, while product purchases were $64.0 million, resulting in a net margin of $6.6 million in 2002. The 2002 net margin represents a decrease of $6.3 million compared to a net margin in 2001 of $12.9 million resulting from product sales for the year ended December 31, 2001 of $108.2 million and product purchases of $95.3 million. The margin decline in 2002 reflects our agreement with an affiliate of Williams to provide blending services for them for an annual fee rather than generating a commodity margin in relation to this activity from April 2002 through December 2002.

Affiliate management fee revenues for the year ended December 31, 2002 were $0.2 million compared to $1.0 million for the year ended December 31, 2001. Historically, the petroleum products pipeline system received a fee to manage an affiliate pipeline.

Depreciation and amortization expense for the year ended December 31, 2002 was $35.1 million, representing a $0.7 million decrease from 2001 at $35.8 million. Additional depreciation associated with acquisitions and capital improvements was more than offset by the elimination of depreciation associated with assets that previously were a part of Magellan Pipeline but were excluded from the assets transferred to us when we acquired the petroleum products pipeline system.

G&A expenses for the year ended December 31, 2002 were $43.2 million compared to $47.3 million for the year ended December 31, 2001, a decrease of $4.1 million, or 9%. Prior to our acquisition of the petroleum products pipeline system, this operating unit was allocated G&A costs from Williams based on a multi-factor formula. Following the acquisition, G&A expenses that we paid to Williams for this pipeline system were subject to an expense limitation, which resulted in a lower G&A costs to us. Incentive compensation costs associated with our long-term incentive plan were specifically excluded from the expense limitation and were $3.7 million during 2002 and $2.0 million during 2001. The 2002 incentive compensation costs included $2.1 million associated with the early vesting of the restricted units issued to key employees at the time of our initial public offering. The early vesting was triggered as a result of meeting targets for our growth in cash distributions paid to unitholders.

Net interest expense for the year ended December 31, 2002 was $21.8 million compared to $12.1 million for the year ended December 31, 2001. The increase in interest expense was primarily related to the debt financing of the petroleum products pipeline system. Although the weighted-average interest rates decreased from 5.0% in 2001 to 4.3% in 2002, the weighted-average debt outstanding increased from $113.3 million in 2001 to $463.9 million in 2002.

We do not pay income taxes because we are a partnership. However, earnings from the petroleum products pipeline system were subject to income taxes prior to our acquisition of it in April 2002, and our pre-initial public offering earnings in 2001 were also taxable. Taxes on these earnings were at income tax rates of 37% and 39% for the year ended December 31, 2002 and 2001, respectively, based on the effective income tax rate for Williams as a result of Williams' tax-sharing arrangement with its subsidiaries. The effective income tax rate exceeds the U.S. federal statutory income tax rate primarily due to state income taxes.

Net income for the year ended December 31, 2002 was $99.2 million compared to $67.9 million for the year ended December 31, 2001, an increase of $31.3 million, or 46%. The operating margin increased by $23.0 million during the period, largely as a result of increased revenues and reduced operating expenses including environmental expenses net of reimbursements for the petroleum products pipeline system, earnings from the acquisitions of the Little Rock and Gibson terminal facilities and increased utilization and rates at our Gulf Coast marine facilities. Depreciation expense and G&A expenses decreased by $0.7 million and $4.1 million, respectively, while net interest expense increased by $9.7 million. Debt placement fee amortization expense increased $9.7 million primarily due to costs from debt financing associated with the petroleum products pipeline system acquisition. Other income increased $1.7 million primarily due to a gain on the sale of assets during 2002 and an impairment charge recorded during 2001 related to the inactive refinery site at Augusta, Kansas, the assets and liabilities of which were not transferred to us as part of our acquisition of the petroleum products pipeline system. Income taxes decreased $21.2 million due to our partnership structure.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

During 2003, net cash provided by operating activities exceeded distributions paid and maintenance capital requirements by $32.6 million. Our cash distributions exceeded the minimum quarterly distribution of $0.525 per unit by $38.2 million.

Net cash provided by operating activities was $144.0 million for the year ended December 31, 2003, $161.0 million for 2002 and $135.3 million for 2001.

- The $17.0 million decrease from 2002 to 2003 was primarily attributable to:
  - reduced net income of $11.0 million principally resulting from the one-time costs related to the 2003 change in control of our general partner that impacted the current year;
  - an increase in inventory of $12.1 million during 2003 resulting from our July 2003 purchase of a petroleum products management operation. The corresponding increase in accrued product purchases of $8.5 million partially offset the inventory change; and

- non-cash one-time expenses associated with the change of control of our general partner in 2003 were generally offset by changes in our affiliate assets and liabilities.

- The $25.7 million increase in cash from operating activities from 2001 to 2002 was primarily attributable to an increase in net income of $31.3 million and changes in operating assets and liabilities. Changes in operating assets and liabilities reduced net cash from operating activities by $7.2 million and were principally attributable to:
  - an increase in accounts receivable and other accounts receivable of $15.4 million. As part of our acquisition of the petroleum products pipeline system in April 2002, Williams retained $15.0 million of receivables resulting in a significant increase in receivables during 2002 as the receivables retained by Williams were replaced in the ordinary course of business;
  - a reduction in inventory of $18.3 million due to the elimination of inventories associated with the petroleum products management operation retained by Williams at the time of our acquisition of the petroleum products pipeline system; and
  - net affiliate assets and liabilities increased $17.6 million. However, $5.0 million of the increase was offset by related increases in environmental liabilities indemnified by affiliates. The remaining increase of $12.6 million was due primarily to establishing affiliate receivables for environmental liabilities indemnified at the time of our acquisition of the petroleum products pipeline system.

Net cash used by investing activities for the years ended December 31, 2001, 2002 and 2003 was $87.5 million, $727.0 million and $45.9 million, respectively. During 2003, we acquired our petroleum products management operation. During 2002, we acquired our petroleum products pipeline system and the Aux Sable natural gas liquids pipeline. During 2001, we acquired our two Little Rock inland terminals and the Gibson marine facility. We also invested capital to maintain our existing assets. Total maintenance capital spending before reimbursements was $24.4 million, $26.4 million and $20.9 million in 2001, 2002 and 2003, respectively. Please see *Capital Requirements* below for further discussion of capital expenditures as well as maintenance capital amounts net of reimbursements.

Net cash provided (used) by financing activities for the years ended December 31, 2001, 2002 and 2003 was $(34.0) million, $627.3 million and $(61.8) million, respectively. Cash was used during 2003 primarily to pay cash distributions to our unitholders. Cash provided during 2002 principally included the debt and equity funding that were completed in conjunction with our acquisition of the petroleum products pipeline system. Cash was used in 2001 to repay affiliate notes associated with the assets held at the time of our initial public offering assets as well as payments made by our petroleum products pipeline system to decrease its affiliate note balance, partially offset by proceeds from debt borrowings and equity issued in our initial public offering and subsequent debt borrowings for acquisitions.

During 2003, we paid $90.5 million in cash distributions to our unitholders. The quarterly distribution amount associated with the fourth quarter of 2003 was $0.83 cents 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 $103.2 million will be paid to our unitholders annually. Of this amount, $12.3 million, or 12%, is related to our general partner's 2% ownership interest and incentive distribution rights.

Capital Requirements

The transportation, storage and distribution business requires continual investment to upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. The capital requirements of our businesses consist primarily of:

- maintenance capital expenditures, such as those required to maintain equipment reliability and safety and to address environmental regulations; and
- payout capital expenditures to acquire additional complementary assets to grow our business and to expand or upgrade our existing facilities, such as projects that increase storage or throughput volumes or develop pipeline connections to new supply sources.

Williams agreed to reimburse us for maintenance capital expenditures incurred in 2001 and 2002 in excess of $4.9 million per year related to the assets held at the time of our initial public offering. This reimbursement obligation was subject to a maximum combined reimbursement for both years of $15.0 million. During 2001 and 2002, we recorded reimbursements from Williams associated with these assets of $3.9 million and $11.0 million, respectively.

In connection with our acquisition of Magellan Pipeline, Williams agreed to reimburse us for maintenance capital expenditures incurred in 2002, 2003 and 2004 in excess of $19.0 million per year related to this pipeline system, subject to a maximum combined reimbursement for all years of $15.0 million. Our maintenance capital expenditures related to the petroleum products pipeline system for 2002 and 2003 were less than $19.0 million per year and we expect that they will be less than $19.0 million in 2004. Therefore, we do not anticipate reimbursement by Williams associated with this agreement.

During 2003, our maintenance capital spending net of environmental reimbursements was $12.2 million. Reimbursable environmental projects were $3.6 million during 2003. Further, we spent an additional $5.0 million of capital associated with our separation from Williams, or $3.4 million net of reimbursements. We expect to incur maintenance capital expenditures for 2004 for all of our businesses of approximately $19.0 million, net of reimbursable environmental projects.

In addition to maintenance capital expenditures, we also incur payout capital expenditures at our existing facilities for expansion and upgrade opportunities. During 2003, we spent $29.0 million of payout capital, including acquisitions. Based on projects currently in process, we plan to spend approximately $16.0 million of payout capital in 2004 on organic growth projects. This amount does not include capital expenditures made in connection with future acquisitions. We expect to fund our payout capital expenditures, including any acquisitions, from:

- cash provided by operations;
- borrowings under the revolving credit facility discussed below and other borrowings; and
- the issuance of additional common 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.

Liquidity

Magellan Pipeline (formerly Williams Pipe Line) Senior Secured Notes. In connection with the long-term financing of our acquisition of the petroleum products pipeline system, we and our subsidiary, Magellan Pipeline, entered into a note purchase agreement on October 1, 2002. We made two borrowings under this agreement. The first borrowing for $420.0 million in November 2002 was used to repay a short-term loan and related debt placement fees. The second borrowing for $60.0 million in December 2002 was used primarily to repay the outstanding acquisition sub-facility of the OLP term loan and credit facility described below.

The borrowings included Series A and Series B notes. The maturity date of these notes is October 7, 2007, with scheduled prepayments equal to 5% of the outstanding balance due on both October 7, 2005 and October 7, 2006. The debt is secured by our membership interests in and the assets of Magellan Pipeline. Payment of interest and principal is guaranteed by the Partnership.

The Series A notes include $178.0 million of borrowings that incur interest based on the six-month Eurodollar rate plus 4.3%. The Series B notes include $302.0 million of borrowings that incur interest at a weighted-average fixed rate of 7.8%.

In the event of a change in control of our general partner, each holder of the notes has 30 days within which it could exercise a right to put its notes to Magellan Pipeline unless the new owner of our general partner has: (i) a net worth of at least $500.0 million and (ii) long-term unsecured debt rated as investment grade by both Moody's Investor Service Inc. and Standard & Poor's Rating Service. For these notes, a change in control is defined as the acquisition by any person of 50% or more of the interest in our general partner. The holders of these notes waived their put rights with respect to the change in control of our general partner.

The note purchase agreement contains various operational and financial covenants that restrict our ability to borrow additional funds. The most significant of these is a leverage ratio that limits our debt-to-EBITDA ratio, as defined in the note purchase agreement, to 4.5 to 1.0. We are in compliance with all of these covenants.

Magellan Midstream Partners term loan and revolving credit facility. On August 6, 2003, we entered into a new credit agreement with a syndicate of banks. This facility, which replaced the OLP term loan and revolving credit facility discussed below, is initially comprised of a $90.0 million term loan and an $85.0 million revolving credit facility. Up to $10.0 million of the revolving credit commitments are available for letters of credit. As of December 31, 2003, the $90.0 million term loan was outstanding with $0.2 million of the $85.0 million revolving credit facility utilized for a letter of credit and the balance available for future borrowings.

The term loan portion of this borrowing was assigned a credit rating by the two largest rating agencies in the United States. Standard & Poor's Rating Service rated us BBB−, and Moody's Investor Service Inc. rated us Ba1.

Indebtedness under the term loan initially incurred interest at the Eurodollar rate plus a margin of 2.4%, while indebtedness under the revolving credit facility incurred interest at the Eurodollar rate plus a margin of 1.8%. However, effective December 22, 2003, we amended the credit facility resulting in a lower margin spread. The new rate is the Eurodollar rate plus 2.0%. We also incur a commitment fee on the un-drawn portion of the revolving credit facility. The facility provides for the establishment of up to $100.0 million in additional term loans, which would bear interest at a rate agreed to at the time of borrowing. The term loan matures on August 6, 2008, with scheduled prepayments equal to 1.0% of the initial term loan balance due on August 6 of each year until maturity. The revolving credit facility terminates on August 6, 2007.

Obligations under the facility are secured by our partnership interests in the entities which hold our petroleum products terminals and ammonia pipeline system. Those entities are also guarantors of our obligations under the facility. Magellan Pipeline is a separate operating subsidiary of ours and is not a guarantor under this facility.

Under the terms of this facility, a change in control will result in an event of default, in which case the maturity date of the obligations under the facility may be accelerated. For this facility, a change in control is defined in a variety of ways, each of which involve the current owners of MMH no longer maintaining majority control of the management of us, MMH or our general partner.

The note purchase agreement contains various operational and financial covenants that restrict our ability to borrow additional funds. The most significant of these is a leverage ratio that limits our debt-to-EBITDA ratio, as defined in the credit agreement, to 4.5 to 1.0. We are in compliance with all of these covenants.

OLP term loan and revolving credit facility. Subsequent to the closing of our initial public offering on February 9, 2001, we relied on cash generated from operations as our primary source of funding, except for payout capital expenditures. Additional funding requirements were met by a $175.0 million credit facility of Williams OLP, L.P. (which was renamed Magellan OLP, L.P. effective September 1, 2003), parent to our petroleum products terminals and ammonia pipeline system. This credit facility was comprised of a $90.0 million term loan and an $85.0 million revolving credit facility.

This facility, which was due to mature on February 5, 2004, had the $90.0 million term loan outstanding when it was repaid in full on August 6, 2003 with the proceeds from borrowings under the term loan of the credit facility described above.

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 is 53% at December 31, 2003. Because accounting rules required the acquisition of our petroleum products pipeline system to be recorded at historical book value due to the 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. If this pipeline system had been acquired from a third party at the identical purchase price, the asset would have been recorded at market value, resulting in a debt-to-total capitalization of 37%. This pro forma debt-to-total capitalization ratio is presented in order to provide our investors with an understanding of what our debt-to-total capitalization position would have been had we made a similar acquisition from a third-party entity. We believe this presentation is important in comparing our debt-to-total capitalization ratio to that of other entities.

Off-Balance Sheet Arrangements

None

Contractual Obligations

The following table summarizes certain contractual obligations as of December 31, 2003 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term and current debt obligations	$570.0	$ 0.9	$49.8	$519.3	$ —
Operating lease obligations	$ 34.9	$ 7.3	$ 7.2	$ 6.0	$14.4
Purchase commitments:					
Affiliate operating and G&A	(1)				
Capital projects	$ 28.2	$28.2	$ —	$ —	$ —
Petroleum product purchases	$ 2.5	$ 2.5	$ —	$ —	$ —
Other	$ 4.3	$ 1.0	$ 1.9	$ 1.4	$ —

(1) We have an agreement with MMH, an affiliate entity, for operating and G&A costs associated with our activities. The agreement requires us to pay for actual operating costs incurred by MMH on our behalf and for G&A costs incurred on our behalf up to the expense limitations as imposed by the new Omnibus Agreement. The agreement, which began on June 17, 2003, has a five-year term but has provisions for termination upon 90-day notice by either party. As a result of the termination provision and the agreements requirement to pay only MMH's costs as they are incurred, we are unable to determine the actual amount of this commitment.

Environmental

Our operations are subject to environmental laws and regulations, adopted by various governmental authorities, in the jurisdictions in which these operations are conducted. We have accrued liabilities for estimated site restoration costs to be incurred in the future at our facilities and properties. Under our accounting policies, liabilities are recorded when site restoration and environmental remediation and cleanup obligations are either known or considered probable and can be reasonably estimated.

Williams, certain of its affiliates and MMH will indemnify us against certain environmental liabilities. Williams has guaranteed the obligations of its affiliates. The terms and limitations of these indemnification agreements are summarized below.

For assets transferred to us from Williams at the time of our initial public offering in February 2001, Williams agreed to indemnify us for up to $15.0 million for environmental liabilities that exceed the amounts covered by the indemnities we received from the sellers of those assets. We refer to this indemnity in the table below as the IPO Indemnity. The indemnity applies to environmental liabilities arising from conduct prior to the closing of the initial public offering (February 9, 2001) and discovered within three years of closing of the initial public offering; however, the discovery period has been extended to August 9, 2004.

In connection with our April 2002 acquisition of Magellan Pipeline, which owns our petroleum products pipeline, Williams has agreed to indemnify us for losses and damages related to breaches of representations and warranties, including environmental representations and warranties and the violation or liabilities arising under any environmental laws prior to the acquisition. This indemnity covers losses in excess of $2.0 million up to a maximum of $125.0 million. We refer to this indemnity in the table below as the Magellan Pipeline Indemnity. Claims related to this environmental indemnity must be made prior to April 2008 and must be related to events that occurred prior to April 11, 2002.

In addition to these two agreements, the purchase and sale agreement ("June 2003 PSA") entered into in connection with MMH's acquisition of us provides us with two additional indemnities related to environmental liabilities, which we cumulatively refer to as the Acquisition Indemnity in the table below.

First, MMH (the buyer under the June 2003 PSA) assumed Williams' obligations to indemnify us for $21.9 million of known environmental liabilities, of which $19.0 million was associated with known liabilities at Magellan Pipeline facilities, $2.7 million was associated with known liabilities at our petroleum products terminal facilities and $0.2 million was associated with known liabilities on the ammonia pipeline system.

Second, in the June 2003 PSA, Williams agreed to indemnify us for certain environmental liabilities arising prior to June 17, 2003 related to all of our facilities to the extent not already indemnified under Williams' two preexisting indemnification obligations described above. This additional indemnification includes those liabilities related to our petroleum products terminals and the ammonia pipeline system arising after the initial public offering (February 9, 2001) through June 17, 2004 and those liabilities related to Magellan Pipeline arising after our acquisition of it on April 11, 2002 through June 17, 2003. This indemnification covers environmental as well as other liabilities and is capped at $175.0 million.

A summary of the indemnities we have with Williams, total claims against those indemnities and the amount of those indemnities remaining is provided below.

	Maximum Indemnity Amount	Claims Against Indemnity	Amount of Indemnity Remaining
IPO Indemnity	$ 15.0	$ 3.4	$ 11.6
Magellan Pipeline Indemnity	125.0	18.0	107.0
Acquisition Indemnity	175.0	0.7	174.3
Total	$315.0	$22.1	$292.9

Impact of Inflation

Although inflation has slowed in recent years, it is still 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 along increased costs to our customers in the form of higher fees.

Critical Accounting Estimates

Goodwill Impairment

In January 2002, we began applying the rules promulgated by Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangibles", relative to accounting for goodwill and other intangible assets. Under this standard we no longer amortize goodwill because it is an asset with an indefinite useful life but test it for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. The first step of the impairment test is to determine if the fair value of our reporting units exceed their carrying amount. If the fair value of the reporting unit is less than its carrying amount then the goodwill may be impaired. The second step compares the implied fair value of goodwill to its carrying amount. If the carrying amount of goodwill exceeds its implied fair value, an impairment loss is recognized equal to that excess. The implied fair value of goodwill should be calculated in the same manner that goodwill is calculated in a business combination.

Goodwill included in our consolidated balance sheet was $22.1 million at December 31, 2003 and $22.3 million at both December 31, 2002 and 2001. The change in goodwill during 2003 was the result of a purchase price adjustment created by a contingency payment associated with the acquisition of our Little Rock, Arkansas terminal. All of the goodwill and other intangibles recognized by us are associated with the petroleum products terminals segment and were acquired as part of the Gibson, Louisiana and Little Rock, Arkansas terminals acquisitions. We performed our annual testing of goodwill, as required by SFAS No. 142, as of October 1, 2003.

We believe that the accounting estimate related to goodwill impairment is a "critical accounting estimate" of our petroleum products terminals segment because: (1) significant judgment is exercised during the process of determining the petroleum products terminals segment fair value and (2) because different assumptions could result in material charges to our operating results.

For the 2003 test, fair value of the petroleum products terminals was assessed using two approaches: (1) a discounted future cash flows approach, and (2) an EBITDA multiple approach. The discounted future cash flows model assumed a 9.5% discount rate based on an expected 12% return on equity and a 7% cost of debt and a 50/50 debt-to-equity ratio. Under the EBITDA multiple approach, we applied a multiple of 9 times the adjusted EBITDA of the petroleum products terminals segment to determine fair value. We define EBITDA as income before income taxes plus interest expense (net of interest income), depreciation and amortization expense and debt placement fee amortization. EBITDA multiples are used industry-wide in assessing values for business assets similar to those in our petroleum products terminals segment. The EBITDA of the petroleum products terminals segment was adjusted to exclude a portion of the general and administrative expenses to take into consideration expected synergies.

Under both of the methodologies described above the fair value of the petroleum products terminals segment exceeded the carrying value of the segment. Therefore, we did not recognize an impairment in 2003. In reaching the conclusion above, more confidence was placed on the discounted cash flow model because management believes this approach provides a better assessment of the actual value that a willing buyer and willing seller could agree upon.

The critical factors in the discounted cash flow model are the required rate of return on equity and the cost of debt. A chart showing the implied impairments under various assumed changes in the estimates is provided below (in millions):

	Debt / Equity Ratio = 50 / 50				
Debt Cost	7%	8%	9%	10%	11%
Equity Cost	12%	13%	14%	15%	16%
Implied Impairment	$ —	$ —	$ —	$ —	$16.9

Based on the table one can determine that, assuming all other factors remain constant, if debt costs increased from our assumed rate of 7% to 11%, combined with an increase in our assumed required rate of return on equity from 12% to 16%, the assets of the petroleum products terminals segment would be impaired. It is likely that under this scenario the entire $22.1 million of goodwill would be impaired. Because we pay no income taxes, the impairment would reduce operating profit and net income by $22.1 million, which represents a 18% decrease in operating profit and a 25% decrease in net income for 2003. Assuming our current distribution levels for an entire year, this impairment would reduce both basic and diluted net income per limited partner unit by approximately $0.72.

Our management has discussed the development and selection of this critical accounting estimate with the Audit Committee of our general partner's Board of Directors and the Audit Committee has reviewed this disclosure.

Environmental Liabilities

We estimate the liabilities associated with environmental expenditures based on site-specific project plans for remediation, taking into account prior remediation experience. Experienced remediation project managers evaluate each known case of environmental liability to determine what phases and associated costs can be reasonably estimated and to ensure compliance with all applicable federal and/or 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 1 to 10 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 also 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 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 complete.

Each quarter, we reevaluate 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 and/or changes in federal or state regulations. The estimated environmental liability accruals are adjusted as necessary.

At December 31, 2001, our environmental liabilities were $16.9 million. During 2002, we spent $6.4 million for environmental remediation but also made significant accrual adjustments to six environmental projects. These adjustments resulted in an increase in our environmental liabilities of $10.5 million. Accruals for all other projects, including five new projects identified during the year, were $1.3 million, resulting in the December 31, 2002 environmental liability of $22.3 million. The $10.5 million increase in our environmental liabilities during 2002 was the result of additional work and reassessments at the six previously mentioned terminals on our petroleum products pipeline system. Williams indemnified these liabilities; consequently, there was no impact to our operating profit or net income from these accrual increases. During 2003, we spent $9.4 million for environmental remediation. During 2003, we experienced a leak on our petroleum products pipeline near Kansas City, Kansas, which resulted in an increase to our environmental liabilities of $4.8 million. Insurance proceeds are expected to cover $3.1 million of these costs and the remaining $1.7 million was charged against our income in 2003. The recommendations that came from the annual and quarterly review process during 2003 resulted in our increasing the environmental liabilities associated with over 100 separate remediation sites by approximately $9.1 million. These accrual increases did not have a significant impact our operating profit or net income because

Williams indemnified most of the increases. Our environmental liabilities at December 31, 2003 were $26.8 million.

Based on the assumption of an additional 15% increase in our estimated environmental liabilities and further assuming that none of those additional liabilities would be indemnified, our expenses would increase by $4.0 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 3% of our operating profit and 5% of our net income for 2003. 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 $0.13. Such a change would result in less than a 1% increase in both our total liabilities and total equity. The impact of such an increase in environmental 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".

Our management has discussed the development and selection of this critical accounting estimate with the Audit Committee of our general partner's Board of Directors and the Audit Committee has reviewed this disclosure.

Environmental Receivables

As described above, we have agreements which indemnify us against certain environmental liabilities, the most significant of which are with Williams and MMH. When a site-specific environmental liability is recognized, a determination is made as to whether or not the liability is indemnified. If so, a receivable for the amount of the indemnified liability is also recognized. We do not require payment from the indemnifying party until actual remediation work is performed on the site. At that time, the indemnifying party is billed for the remediation work and the cash received is used to reduce the environmental receivable. Changes in our environmental receivables since December 31, 2001 are as follows (in millions):

Indemnifying Party	Balance 12/31/01	2002 Accruals	2002 Payments	Balance 12/31/02	2003 Accruals	2003 Transfers	2003 Payments	Balance 12/31/03
Williams	$ 3.2	$24.3	$(4.5)	$23.0	$ 9.5	$(21.9)	$(2.8)	$ 7.8
MMH	—	—	—	—	—	21.9	(2.9)	19.0
Other	—	—	—	—	3.1	—	—	3.1
Totals	$ 3.2	$24.3	$(4.5)	$23.0	$12.6	$ —	$(5.7)	$29.9

We believe that the accounting estimate related to affiliate receivables is a "critical accounting estimate" because: (1) its carrying amount is subject to many of the same estimates as those used to develop the underlying environmental liabilities (see Critical Accounting Estimates—Environmental Liabilities above); and (2) given Williams' unfavorable financial status in recent years, it requires our management's estimations involving Williams' ability to pay and our ability to collect the receivable amount.

Should Williams be unable to perform on its existing obligations, we may be unable to collect part or all of this environmental account receivable. In preparing our financial statements for the year ended December 31, 2003, management's assumptions were that we would be able to collect the full amount of this receivable from Williams.

Any change in our estimate of the amount of the receivable we believe we can ultimately collect from Williams would require us to take a charge against income because we have not recorded any allowance for doubtful accounts associated with this receivable. If none of the receivable were collectable, we would have a charge against income of $7.8 million, which represents 6% of our operating profit and 9% of our net income for 2003. 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 $0.25. The impact of such a charge would likely not have affected our liquidity because, even with the increased expense, we would still comply with the covenants of our long-term debt agreements as discussed above under "Liquidity and Capital Resources—Liquidity".

Our management has discussed the development and selection of this critical accounting estimate with the Audit Committee of our general partner's Board of Directors and the Audit Committee has reviewed this disclosure.

New Accounting Pronouncements

In December 2003, the Financial Accounting Standards Board ("FASB") issued a revision to Statement of Financial Accounting Standards ("SFAS") No. 132 "Employers' Disclosures about Pensions and Other Postretirement Benefits". This revision requires that companies provide more details about their plan assets, benefit obligations, cash flows, benefit costs and other relevant information. A description of investment policies and strategies and target allocation percentages, or target ranges, for these asset categories also are required in financial statements. Cash flows will include projections of future benefit payments and an estimate of contributions to be made in the next year to fund pension and other postretirement benefit plans. In addition to expanded annual disclosures, the FASB is requiring companies to report the various elements of pension and other postretirement benefit costs on a quarterly basis. The guidance is effective for fiscal years ending after December 15, 2003, and for quarters beginning after December 15, 2003.

In May 2003, the FASB issued SFAS No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This Statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. This statement had no impact on our financial position, results of operations or cash flows upon its initial adoption.

In April 2003, the FASB issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". This Statement is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. In addition all provisions of this Statement must be applied prospectively. This Statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as "derivatives") and for hedging activities under FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. The initial application of this Statement did not have a material impact on our financial position, results of operations or cash flows.

In December 2002, the FASB issued SFAS No. 148 "Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of FASB Statement No. 123". This Statement amends FASB Statement No. 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. This Statement improves the prominence and clarity of the pro forma disclosures required by Statement 123 by prescribing a specific tabular format and by requiring disclosure in the "Summary of Significant Accounting Policies" or its equivalent. The standard is effective for fiscal periods ending after December 15, 2002. Although we account for stock-based compensation for Williams employees assigned to the Partnership under provisions of Accounting Principles Board Opinion No. 25, the structure of the awards is such that we fully recognize compensation expense associated with unit awards. Hence, had we adopted this standard, it would not have had a material impact on our operations or financial position.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. We adopted this standard in January 2003 and it did not have a material impact on our results of operations or financial position.

In the second quarter of 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13 and Technical Corrections". The rescission of SFAS No. 4 "Reporting Gains and Losses from Extinguishment of Debt," and SFAS No. 64, "Extinguishment of Debt Made to Satisfy Sinking-Fund Requirements," requires that gains or losses from extinguishment of debt only be classified as extraordinary items in the event they meet the criteria in Accounting Principle Board Opinion ("APB") No. 30, "Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". SFAS No. 44, "Accounting for Intangible Assets of Motor Carriers," established accounting requirements for the effects of transition to the Motor Carriers Act of 1980 and is no longer required now that the transitions have been completed. Finally, the amendments to SFAS No. 13 "Accounting for Leases" are effective for transactions occurring after May 15, 2002. All other provisions of this Statement will be effective for financial statements issued on or after May 15, 2002. We adopted this standard in January 2003, and it did not have a material impact on our results of operations or financial position. However, in subsequent reporting periods, any gains and losses from debt extinguishments will not be accounted for as extraordinary items.

Related Party Transactions

Affiliate revenues historically represented revenues from Williams and its affiliates. Subsequent to Williams' sale of its interests in us on June 17, 2003, we no longer have affiliate revenues. Affiliate revenues have declined significantly over the past three years; however, total revenues have increased. Amounts are summarized in the table below (in millions):

	2001	2002	2003
Affiliate revenues	$ 94.3	$ 58.6	$ 13.9
Total revenues	$448.6	$434.5	$485.2
Affiliate revenues as a percent of total revenue	21%	13%	3%

We had agreements with Williams Energy Marketing & Trading, LLC ("WEM&T") which provided for: (i) the lease of a Carthage, Missouri propane storage cavern and (ii) access and utilization of storage on the Magellan Pipeline system. Magellan Pipeline had entered into pipeline lease agreements and tank storage agreements with Mid-America Pipeline Company ("MAPL") and Williams Bio-Energy, LLC ("Williams Bio-Energy"), respectively. MAPL was an affiliate entity until its sale by Williams in July 2002 and Williams Bio-Energy was an affiliate entity until its sale by Williams in May 2003. The Partnership also had a lease storage contract with Williams Bio-Energy at its Galena Park, Texas marine terminal facility.

We also had an agreement with WEM&T, which provided for storage and other ancillary services at our marine terminal facilities. This agreement was cancelled during the first quarter of 2003 in exchange for a $3.0 million payment to us from WEM&T. Both WEM&T and Williams Refining & Marketing had agreements for the access and utilization of the inland terminals.

In addition, we had an agreement with Williams Petroleum Services, LLC to perform services related to petroleum product asset management activities for an annual fee in 2003 of approximately $4.0 million. In July 2003, we acquired from Williams and its affiliates the rights to these activities.

We also had affiliate agreements with WEM&T and Williams Refining & Marketing, LLC for the non-exclusive and non-transferable sub-license to use the ATLAS 2000 software system. The rights to this system were contributed to us on June 17, 2003.

The following table reflects revenues from various Williams' subsidiaries through June 17, 2003 (in thousands):

	Year Ended December 31,		
	2001	2002	2003
Williams 100%-Owned Affiliates:			
Williams Energy Marketing & Trading	$ 75,717	$ 40,119	$ 7,425
Williams Refining & Marketing	13,519	8,164	306
Williams Bio-Energy	3,448	4,842	2,366
Midstream Marketing & Risk Management	—	1,719	598
Mid-America Pipeline	285	165	—
Williams Petroleum Services, LLC	—	2,625	2,992
Other	—	749	—
Williams Partially-Owned Affiliates:			
Longhorn Pipeline Partners	1,301	210	—
Rio Grande Pipeline	—	—	225
Total	$ 94,270	$ 58,593	$13,912

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 between the Partnership and MMH and its affiliates were accounted for as affiliate transactions after June 17, 2003. The following table summarizes costs and expenses from various affiliate companies with us and are reflected in the cost and expenses in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2001	2002	2003
Williams Energy Services—direct and directly allocable expenses	$ 29,242	$ 8,231	—
Williams—allocated general and administrative expenses	18,123	34,951	23,880
Williams—allocated operating and maintenance expenses	160,880	155,146	68,079
Williams Energy Marketing & Trading—product purchases	80,959	22,268	472
Mid-America Pipeline—operating and maintenance expenses	2,730	1,318	—
MMH—allocated operating and maintenance expenses	—	—	98,804
MMH—allocated general and administrative expenses	—	—	32,966

In 2001, 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated both direct and indirect general and administrative expenses to our general partner. Direct expenses allocated by Williams were primarily salaries and benefits of employees and officers associated with the business activities of the affiliate. Indirect expenses include legal, accounting, treasury, engineering, information technology and other corporate services. Williams allocated these expenses to our general partner based on the expense limitation provided for in the omnibus agreement. We reimbursed our general partner and its affiliates for expenses charged to us by our general partner on a monthly basis. As a result, of the sale of Williams' ownership interests in us, we entered into a new services agreement with MMH pursuant to which MMH agreed to perform specified services required for our operation. Consequently, our operations and general and administrative functions are now provided by MMH. Our reimbursement of general and administrative costs is subject to the limitations as defined in the new omnibus agreement. In addition, in 2001, 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated operating and maintenance expenses to the Partnership's general partner. Expenses included all costs directly associated with the operations of the Partnership's businesses. From June 17, 2003 through December 31, 2003 operating expenses were allocated to the Partnership's general partner from MMH.

Beginning with the closing date of the initial public offering, our general partner, through provisions included in the omnibus agreement, agreed that for the assets associated with the petroleum products terminals and ammonia pipeline system operations, we would reimburse our general partner for general and administrative costs up to a specified expense limitation. In addition, beginning with the acquisition of Magellan Pipeline, our general partner agreed that for these assets, we would reimburse our general partner for general and administrative costs up to a specified expense limitation.

MAPL and we had an operating agreement whereby MAPL operated the ammonia pipeline system for us for a fee. On July 31, 2002, Williams sold 98% of Mapletree LLC, which owned MAPL, to Enterprise Products Partners L.P. ("Enterprise"). All transactions between us, MAPL and Enterprise after July 31, 2002 have been recorded as unaffiliated third-party transactions.

Historically, Magellan Pipeline had an agreement with WEM&T to purchase transmix for fractionation and product to settle shortages. For the periods that MAPL was an affiliate of the Partnership, MAPL provided operating and maintenance support, to the ammonia pipeline and leased storage space to Magellan Pipeline.

Williams and certain of its affiliates and MMH have indemnified us against certain environmental costs. Receivables from Williams or its affiliates associated with these environmental costs were $7.8 million and $22.9 million at December 31, 2003 and December 31, 2002, respectively, and are included with accounts receivable amounts presented in the consolidated balance sheets. Receivables from MMH were $19.0 million at December 31, 2003 and are included with the affiliate accounts receivable in the consolidated balance sheets. A description of Williams' and MMH's indemnities to us is included in the Environmental section above.

Historically, Williams charged interest expense to its affiliates based on their inter-company debt balances. We also participated in employee benefit plans and long-term incentive plans sponsored by Williams.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements — statements that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

Forward-looking statements can be identified by words such as anticipates, believes, 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 trends and 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;
- changes in our tariff rates implemented by the FERC and the Surface Transportation Board;
- shut-downs or cutbacks at major refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- changes in throughput 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;
- changes in the federal government's policy regarding farm subsidies, which could negatively impact the demand for ammonia and reduce the amount of ammonia transported through 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;
- our ability to integrate any acquired operations into our existing operations;
- our ability to successfully identify and close strategic acquisitions and expansion projects and make cost saving changes in operations;
- changes in general economic conditions in the United States;
- changes in laws and regulations to which we are subject, including tax and state 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 have other adverse consequences;
- the condition of the capital markets and equity markets in the United States;
- the ability to raise capital in a cost-effective way;
- the effect of changes in accounting policies;
- the ability to manage rapid growth;
- Williams' and MMH's ability to perform on their environmental and rights-of-way indemnifications to us;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

Risks Related to our Business

We may not be able to generate sufficient cash from operations to allow us to pay the minimum quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

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 the minimum quarterly distribution for each quarter. Our ability to pay the minimum quarterly distribution each quarter 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 make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent 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 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 terminal facilities 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 crude oil that leads to higher refined products prices, which may reduce demand for gasoline and other petroleum products. Market prices for refined 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, jet 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 or technological advances by manufacturers; and
- the increased use of alternative fuel sources, such as fuel cells and solar, electric and battery-powered engines. Several state and federal initiatives mandate this increased use.

When prices for the future delivery of petroleum products that we transport through our pipeline system or store in our marine terminals fall below current prices, customers are 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, it may affect our ability to meet our financial obligations and pay cash distributions.

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

Most of our inland and marine terminal facilities, which are not connected to our petroleum products pipeline system, depend on connections with petroleum products pipelines owned and operated by third parties. Reduced throughput on these pipelines because of testing, line repair, damage to pipelines, 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 and could adversely affect our ability to meet our financial obligations and pay cash distributions.

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

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the U.S. government has issued warnings that energy assets, specifically our nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments have 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 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 refined petroleum products and ammonia, including 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 have increased significantly and could escalate further. 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 or results of operations.

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 our petroleum products system. Shippers may protest the pipeline's tariffs, and the FERC may investigate the lawfulness of new or changed tariff rates and order refunds of amounts collected under rates ultimately found to be unlawful. The FERC may also investigate tariff rates that have become final and effective.

The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. The FERC's primary ratemaking methodology is price indexing. We use this methodology to establish our rates in approximately one-third of our interstate markets. The indexing method allows a pipeline to increase its rates by a percentage equal to the change in the producer price index, or PPI. Please read "Narrative Description of Business—Tariff Regulation" for further discussion of tariff rates and how they have been impacted by the PPI. If the PPI 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. In addition, changes in the PPI might not be large enough to fully reflect actual increases in the costs associated with operating the pipeline.

In recent decisions involving unrelated partnerships that own pipelines, the FERC has ruled that these partnerships may not claim an income tax allowance for income attributable to non-corporate limited partners. A shipper could rely on these decisions to challenge our indexed rates and claim that, because we now own a petroleum products pipeline system, the pipeline system's income tax allowance should be reduced. If the FERC were to disallow all or part of our income tax allowance, it may be more difficult to justify our rates. If a challenge were brought and the FERC found that some of the indexed rates exceed levels justified by the cost of service, the FERC would order a reduction in the indexed rates and could require reparations for a period of up to two years prior to the filing of a complaint. We establish rates in approximately two-thirds of our markets using the FERC's market-based rate making regulations. These regulations allow us to establish rates based on conditions in individual markets without regard to the index or our costs of service. If successfully challenged, the FERC could take away our ability to establish market-based rates. Any reduction in the indexed rates, removal or our ability to establish market-based rates, or payment of reparations could have a material adverse effect on our operations and reduce the amount of cash we generate.

Mergers among our customers and competitors could result in lower volumes being shipped on our pipelines and/or products stored in or distributed through our terminals, thereby reducing the amount of cash we generate.

Mergers between existing customers 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 revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and pay cash distributions.

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

The U.S. Environmental Protection Agency recently 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 and will be implemented 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 pipeline and the amount of cash we generate.

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. These costs and liabilities arise under increasingly strict 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 the petroleum products pipeline system have been used for many years to transport, distribute or store petroleum products. Over time, operations by us, our predecessors or third parties 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 held jointly and severally liable 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 that they occurred.

In addition, we own 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, owners, tenants or users of these properties have disposed of or released hydrocarbons or solid wastes on or under these properties. In addition, some of our terminals are located on or near current or former refining and terminal operations, and there is a risk that contamination is present on these sites. 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.

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 could require the expenditure of capital. For instance, different product specifications for different markets impacts the fungibility of the system and could require the construction of additional storage. If we are unable to recover these costs through increased revenues, our ability to meet our financial obligations could be adversely affected.

Competition with respect to our operating segments could ultimately 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 petroleum products pipeline system, as well as from other means of transporting, storing and distributing petroleum products. In addition, our marine and inland terminals face competition from large, generally well-financed companies that own many terminals, as well as from small companies. Our marine and inland terminals also encounter competition from 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 use our competitors. We compete primarily with rail carriers for the transportation of ammonia. If our customers elect to transport ammonia by rail rather than pipeline, we may realize lower revenues and cash flows and our ability to meet our financial obligations and pay cash distributions may be adversely affected. Our ammonia pipeline also competes with another ammonia pipeline in Iowa and Nebraska.

Our ammonia pipeline system is dependent on three customers.

Three customers ship all of the ammonia on our pipeline and utilize the six terminals that we own and operate on the pipeline. We have contracts with these three shippers through June 2005 that obligate them to ship-or-pay for specified minimum quantities of ammonia. One of these customers has a credit rating below investment grade. The loss of any one of these three customers or their failure or inability to pay us could adversely affect our ability to meet our financial obligations and pay cash distributions.

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

The profitability of our customers that produce ammonia partially depends on the price of natural gas, which is the principal raw material used in the production of ammonia. Natural gas prices increased late in the fourth quarter of 2002 and have remained high throughout 2003. 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 ability to meet our financial obligations and pay cash distributions.

Williams sold its interests in our general partner in 2003. As a result of the sale, MMH, the entity that purchased Williams' interest, entered into a new Omnibus Agreement with Williams and certain of its affiliates to provide general and administrative services to us, which will result in higher general and administrative expenses and reduce the amount of cash we generate.

In connection with the sale to MMH by Williams of 100% of its ownership interests in our general partner and all of its limited partner interests in us, we are a third-party beneficiary of a new Omnibus Agreement with MMH. There are limitations through 2010 on the amount of general and administrative expenses for which we are required to reimburse MMH and certain of its affiliates, which operate as follows:

- for expenses below a lower cap amount, MMH 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, MMH or its affiliates are required to reimburse us; and
- for expenses above the upper cap amount, MMH and its affiliates are not required to make any reimbursements to us, although Williams will reimburse MMH for these amounts through June 2004.

The initial lower cap amount for 2003 was approximately $37.9 million, but escalates annually beginning in 2004, at 7.0% (or, if greater, the percentage increase in the Consumer Price Index), which is a higher escalation rate than was in effect prior to Williams' sale of its interests in us. The upper cap amount was $49.3 million for 2003, and will escalate annually, beginning in 2004 at the lesser of 2.5% or the percentage increase in the Consumer Price Index. The upper and lower caps will be further adjusted for incremental general and administrative costs associated with acquisitions we consummate.

These limitations on our obligation to reimburse MMH and certain of its affiliates for general and administrative expenses will terminate upon a change in control of MMH 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 general and administrative costs we incur above the lower cap, resulting from the partnership becoming liable for the full amount of general and administrative costs.

The sale of Williams' interests in our general partner required us to separate from Williams. This in turn, required us to obtain services from other sources, which could result in increased costs and limit our ability to meet our obligations and pay cash distributions.

We have entered into a new services agreement with MMH and our general partner. The services provided under the new services agreement include accounting, building administration, human resources, information technology, legal and security, among others. As with our old services agreement, MMH will have the right at any time to terminate its obligations under this services agreement upon 90 days notice. To the extent that neither MMH nor any of its subsidiaries, including our general partner, provides these services to us, the limitations under the new Omnibus Agreement on our reimbursement of general and administrative expenses relating to these services would no longer apply and we may incur increased general and administrative expenses, which could increase our costs and limit our ability to meet our obligations and pay cash distributions.

Indemnities provided by Williams related to assets contributed at our initial public offering, our acquisition of Magellan Pipeline and Williams' sale of its interests in us creates credit exposure to Williams.

Williams and certain of its affiliates have indemnified us for certain liabilities and expenses related to the (1) assets contributed to us at the time of our initial public offering, (2) the contribution of Magellan Pipeline to us in April 2002 and (3) the sale of 100% of their interest in our general partner and all of its limited partner interest in us to MMH. These indemnities primarily address environmental liabilities related to matters that arose

(1) prior to our ownership of these assets and (2) in the case of the MMH transaction, prior to June 2003. Williams has experienced financial and liquidity difficulties that resulted in the loss of its investment grade credit rating. If Williams were unable to perform on its indemnities it would increase our environmental costs and reduce the amount of cash we generate.

Our secured indebtedness could limit our ability to raise cash to fund future obligations or liquidity concerns.

As of December 31, 2003, our total outstanding long-term indebtedness was $570.0 million, including $480.0 million of senior secured notes and $90.0 million under a credit facility. The indebtedness represented by our senior secured notes and under the credit facility is secured by substantially all of our assets.

Covenants in our debt instruments restrict the aggregate amount of debt that we can borrow. In addition, these covenants restrict our ability to incur additional indebtedness or liens, sell assets, make loans or investments, and to acquire or be acquired by other companies. These debt instruments also provide that, if a change in control of MMH or our general partner occurs, this indebtedness may become due. In such event, we cannot assure you that we would be able to repay this indebtedness.

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 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 we generate.

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability. The Internal Revenue Code generally provides that a publicly-traded partnership will be taxed as a corporation. However, an exception, know as the "Qualifying Income Exception," exists with respect to publicly-traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income derived from the transportation, storage and processing of crude oil, natural gas and products thereof and fertilizer. If we fail to meet the Qualifying Income Exception, we may be treated as a corporation for federal income tax purposes.

The 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. If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Some or all of the distributions made to unitholders would be treated as dividend incomes, and no income, gains, losses or deductions would flow through to unitholders. Treatment of us as a corporation would cause a material reduction in our anticipated cash flow due to federal and state taxes, which would reduce our ability to meet our financial obligations and pay cash distributions.

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 or other forms of taxation even though they are treated as partnerships for federal income tax purposes. If any state were to impose a tax upon us as an entity, the cash available to pay distributions would be reduced. The partnership agreement provides that, if a law is enacted or an 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, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

ITEM 7A. *Quantitative and Qualitative Disclosures about Market Risk*

At December 31, 2003, we were not engaged in interest rate or foreign currency exchange rate hedging transactions.

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. Debt we incur under our credit facility and our floating rate series A senior secured notes bear variable interest based on the Eurodollar rate. If the Eurodollar changed by 0.125%, our annual interest obligations associated with the $90.0 million of outstanding borrowings under the term loan and revolving credit facility at December 31, 2003, and the $178.0 million of outstanding borrowings under the floating rate series A senior secured notes would change by approximately $0.3 million. Unless interest rates change significantly in the future, our exposure to interest rate market risk is minimal.

ITEM 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT AUDITORS

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

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2003 and 2002, and the related consolidated statements of income, cash flows and partners' capital for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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, 2003 and 2002, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 8, 2004

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)

	Year Ended December 31,		
	2001	2002	2003
Transportation and terminals revenues:			
Third party	$313,683	$330,545	$359,726
Affiliate	25,729	33,195	13,122
Product sales revenues:			
Third party	40,646	45,339	111,522
Affiliate	67,523	25,188	790
Affiliate management fee revenues	1,018	210	—
Total revenues	448,599	434,477	485,160
Costs and expenses:			
Operating	153,057	152,832	164,612
Environmental	11,559	16,814	14,089
Environmental reimbursements	(3,736)	(14,500)	(11,818)
Product purchases	95,268	63,982	99,907
Depreciation and amortization	35,767	35,096	36,081
Affiliate general and administrative	47,365	43,182	56,846
Total costs and expenses	339,280	297,406	359,717
Operating profit	109,319	137,071	125,443
Interest expense:			
Affiliate interest expense	9,770	407	—
Other interest expense	4,836	22,500	36,597
Interest income	(2,493)	(1,149)	(2,061)
Debt placement fee amortization	253	9,950	2,830
Other income	(431)	(2,112)	(92)
Income before income taxes	97,384	107,475	88,169
Provision for income taxes	29,512	8,322	—
Net income	$ 67,872	$ 99,153	$ 88,169
Allocation of net income:			
Limited partners' interest	$ 21,217	$ 80,713	$ 90,191
General partner's interest	226	4,402	(2,022)
Portion applicable to partners' interests	21,443	85,115	88,169
Portion applicable to non-partnership interests for the period before February 9, 2001, and April 11, 2002 as it relates to the operations of the petroleum products pipeline system	46,429	14,038	—
Net income	$ 67,872	$ 99,153	$ 88,169
Basic net income per limited partner unit	$ 1.87	$ 3.68	$ 3.32
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	11,359	21,911	27,195
Diluted net income per limited partner unit	$ 1.87	$ 3.67	$ 3.31
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	11,370	21,968	27,235

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2002	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 75,151	$ 111,357
Restricted cash	4,942	8,223
Accounts receivable (less allowance for doubtful accounts of $457 and $319 at December 31, 2002 and 2003, respectively)	23,262	19,615
Other accounts receivable	1,395	14,579
Affiliate accounts receivable	15,608	9,324
Inventory	5,224	17,282
Other current assets	3,640	3,941
Total current assets	129,222	184,321
Property, plant and equipment, at cost	1,334,527	1,371,847
Less: accumulated depreciation	401,396	431,298
Net property, plant and equipment	933,131	940,549
Goodwill	22,295	22,057
Other intangibles (less accumulated amortization of $297 and $911 at December 31, 2002 and 2003, respectively)	2,432	11,417
Long-term affiliate receivables	11,656	13,472
Long-term receivables	9,268	9,077
Debt placement costs (less accumulated amortization of $960 and $2,761 at December 31, 2002 and 2003, respectively)	10,543	10,618
Other noncurrent assets	1,812	3,113
Total assets	$1,120,359	$1,194,624
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 16,967	$ 21,200
Affiliate accounts payable	10,123	257
Outstanding checks	1,967	6,961
Accrued affiliate payroll and benefits	6,308	15,077
Accrued taxes other than income	13,697	14,286
Accrued interest payable	4,065	8,196
Environmental liabilities	10,359	12,243
Deferred revenue	11,550	10,868
Accrued product purchases	2,925	11,585
Current portion of long-term debt	—	900
Other current liabilities	3,933	5,310
Total current liabilities	81,894	106,883
Long-term debt	570,000	569,100
Long-term affiliate payable	4,293	1,509
Other deferred liabilities	488	4,455
Environmental liabilities	11,927	14,528
Commitments and contingencies		
Partners' capital:		
Common unitholders (13,680 units and 21,711 units outstanding at December 31, 2002 and 2003, respectively)	399,837	737,715
Subordinated unitholders (5,680 units outstanding at both December 31, 2002 and 2003)	131,194	135,085
Class B common units (7,831 units outstanding at December 31, 2002)	313,651	—
General partner	(391,954)	(373,880)
Accumulated other comprehensive loss	(971)	(771)
Total partners' capital	451,757	498,149
Total liabilities and partners' capital	$1,120,359	$1,194,624

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2001	**2002**	**2003**
Operating Activities:			
Net income	$ 67,872	$ 99,153	$ 88,169
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	35,767	35,096	36,081
Debt placement fee amortization	253	9,950	2,830
Minority interest expense	229	—	—
Deferred income taxes	6,438	1,641	—
Loss/(Gain) on sale and retirement of assets	249	(2,088)	4,563
Changes in operating assets and liabilities (Note 4)	24,525	17,281	12,315
Net cash provided by operating activities	135,333	161,033	143,958
Investing Activities:			
Additions to property, plant & equipment	(39,743)	(37,248)	(34,636)
Proceeds from sale of assets	1,650	2,706	4,034
Acquisitions	(49,409)	(692,493)	(15,346)
Net cash used by investing activities	(87,502)	(727,035)	(45,948)
Financing Activities:			
Distributions paid	(16,599)	(53,373)	(90,527)
Borrowings under credit facility	139,500	8,500	90,000
Payments on credit facility	—	(58,000)	(90,000)
Borrowings under short-term note	—	700,000	—
Payments on short-term note	—	(700,000)	—
Borrowings under long-term note	—	480,000	—
Capital contributions by affiliate	1,792	21,293	21,951
Sales of common units to public (less underwriters' commissions and payment of formation and offering costs)	89,362	279,290	9,477
Debt placement costs	(909)	(19,666)	(2,905)
Redemption of 600,000 common units from affiliate	(12,060)	—	—
Payments on affiliate note payable	(235,090)	(29,780)	—
Payment of interest rate hedge	—	(995)	—
Other	—	47	200
Net cash provided by (used in) financing activities	(34,004)	627,316	(61,804)
Change in cash and cash equivalents	13,827	61,314	36,206
Cash and cash equivalents at beginning of period	10	13,837	75,151
Cash and cash equivalents at end of period	$ 13,837	$ 75,151	$111,357
Supplemental non-cash investing and financing transactions:			
Contributions by affiliate of long-term debt, deferred income tax liabilities, and other assets and liabilities to Partnership capital	$ 73,671	$ 198,117	$ 17,644
Purchase of business through the issuance of class B common units	—	304,388	—
Purchase of Aux Sable pipeline	8,853	—	—

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, 2001	$ 69,856	$ —	$ —	$ 318,647	$ —	$ 388,503
Net income	10,608	10,609	—	46,655	—	67,872
Contribution of net assets of predecessor companies (1.7 million common units and 5.7 million subordinated units issued)	(49,362)	117,884	—	2,290	—	70,812
Redemption of common units (0.6 million units)	(12,060)	—	—	—	—	(12,060)
Issuance of common units to public (4.6 million units)	89,362	—	—	—	—	89,362
Affiliate capital contributions	878	878	—	36	—	1,792
Distributions	(8,134)	(8,134)	—	(331)	—	(16,599)
Balance, December 31, 2001	101,148	121,237	—	367,297	—	589,682
Comprehensive income:						
Net income	40,545	22,734	17,434	18,440	—	99,153
Net loss on cash flow hedge	—	—	—	—	(971)	(971)
Total comprehensive income						98,182
Conversion of minority interest liability to partners' capital	—	—	—	2,270	—	2,270
Conversion of Magellan Pipeline equity to partnership equity and contribution by affiliate	—	—	—	(789,910)	—	(789,910)
Issuance of class B common units (7.8 million units)	—	—	304,388	—	—	304,388
Issuance of common units to public (8.0 million units)	279,290	—	—	—	—	279,290
Affiliate capital contributions	4,536	1,883	2,597	12,277	—	21,293
Distributions	(25,640)	(14,642)	(10,768)	(2,323)	—	(53,373)
Other	(42)	(18)	—	(5)	—	(65)
Balance, December 31, 2002	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 hedge	—	—	—	—	200	200
Total comprehensive income						88,369
Issuance of common units to public (0.2 million units)	9,477	—	—	—	—	9,477
Conversion of class B common units to common units (7.8 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

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Presentation

Magellan Midstream Partners, L.P. (the "Partnership") was 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. The Williams Companies, Inc. ("Williams") formed the Partnership by contributing entities under its common control into the Partnership. Williams Energy Partners L.P. was renamed Magellan Midstream Partners, L.P. effective September 1, 2003.

At the time of the Partnership's initial public offering in February 2001, the Partnership owned petroleum products terminals and an ammonia pipeline system. On April 11, 2002, the Partnership acquired all of the membership interests of Magellan Pipeline Company, LLC ("Magellan Pipeline"), formerly Williams Pipe Line Company, LLC ("Williams Pipe Line"), for approximately $1.0 billion (see Note 6—Acquisitions and Divestitures). Because Magellan Pipeline was an affiliate of the Partnership at the time of the acquisition, the transaction was between entities under common control and, as such, was accounted for similarly to a pooling of interests. Accordingly, the consolidated financial statements and notes of the Partnership reflect the combined historical results of operations, financial position and cash flows of the petroleum products terminals, ammonia pipeline system and Magellan Pipeline throughout the periods presented. Magellan Pipeline's operations are presented as a separate operating segment of the Partnership under the caption "Petroleum Products Pipeline System" (see Note 16—Segment Disclosures).

On April 11, 2002, the Partnership issued 7,830,924 class B common units representing limited partner interests to an affiliate of Williams. The securities were valued at $304.4 million and along with $6.2 million of additional general partner equity interests, were issued as partial payment for the acquisition of Magellan Pipeline (see Note 6—Acquisitions and Divestitures). In December 2003 the class B common units were converted to an equivalent number of common units.

In May 2002, the Partnership issued 8.0 million common units representing limited partner interests in the Partnership at a price of $37.15 per unit for total proceeds of $297.2 million. Associated with this offering, Williams contributed $6.1 million to the Partnership to maintain its 2% general partner interest. A portion of the total proceeds was used to pay underwriting discounts and commissions of $12.6 million. Legal, professional fees and costs associated with this offering were approximately $1.7 million. The remaining cash proceeds of $289.0 million were used to partially repay the $700.0 million short-term note assumed by the Partnership to help finance the Magellan Pipeline acquisition (see Note 13—Debt).

In December 2003, the Partnership issued 200,000 common units representing limited partner interests in the Partnership at a price of $50.00 per unit for total proceeds of $10.0 million. Associated with this offering, the General Partner, contributed $0.2 million to the Partnership to maintain its 2% general partnership 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 will be used for general partnership purposes.

The historical results for Magellan Pipeline, include income and expenses and assets and liabilities that were conveyed to and assumed by an affiliate of Williams prior to the acquisition of Magellan Pipeline by the Partnership. The assets principally included Magellan Pipeline's interest in and agreements related to Longhorn Partners Pipeline, L.P. ("Longhorn"), an inactive refinery site at Augusta, Kansas, a pipeline construction project and the ATLAS 2000 software system. The liabilities principally included the environmental liabilities associated with the inactive refinery site in Augusta, Kansas and current and deferred income taxes and an affiliate note payable. The current and deferred income taxes and the affiliate note payable were contributed to the Partnership in the form of a capital contribution by an affiliate of Williams. The income and expenses associated with

Longhorn have not been included in the financial results of the Partnership since the acquisition of Magellan Pipeline by the Partnership in April 2002. Also, as agreed between the Partnership and Williams, operating results from Magellan Pipeline's petroleum products management operation, other than an annual fee of approximately $4.0 million, were not included in the financial results of the Partnership after April 2002. In addition, general and administrative expenses related to Magellan Pipeline for which the Partnership had been reimbursing its general partner, Magellan GP, LLC ("General Partner"), formerly WEG GP LLC, were limited to $30.7 million on an annual basis. This cap was increased to $31.0 million on February 1, 2003 when Magellan Pipeline began operating the Rio Grande Pipeline. The ATLAS 2000 software system assets were contributed to the Partnership on June 17, 2003, in conjunction with the sale of Williams' interest in the Partnership (see *Change in Ownership of General Partner* below), and the depreciation expense associated with those assets has been included in Partnership's results since that date. Also, the Partnership acquired Williams' interest in the refined petroleum products management operation in July 2003 (see Note 6—Acquisitions and Divestitures), and the results of this operation have been included in the Partnership's results subsequent to that date.

Change in Ownership of General Partner

On June 17, 2003, Williams sold its ownership of 1,079,694 common units, 5,679,694 subordinated units and 7,830,924 class B common units of the Partnership and all of the membership interests of the 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 MLP Holdings, L.P. WEG Acquisitions, L.P. was renamed Magellan Midstream Holdings, L.P. ("MMH") effective September 1, 2003.

ATLAS 2000 Agreement

As part of the overall sales transaction between Williams and MMH, an affiliate of Williams assigned its rights to, and interest in, the ATLAS 2000 software system and associated hardware to the Partnership.

Services Agreement

Prior to June 17, 2003, the Partnership had been a party to a services agreement with Williams and its affiliates whereby Williams and its affiliates agreed to perform specified services, including providing necessary employees to operate the Partnership's assets. On June 17, 2003, Williams exercised its right to terminate this services agreement effective September 15, 2003. During a transition period after June 17, 2003, the employees that managed the Partnership's operations continued to be employees of Williams and its affiliates and, until the employees were transferred to MMH, provided services to the Partnership under a transition services agreement ("TSA") entered into as a part of the sales transaction between Williams and MMH. Under the provisions of the TSA, Williams was to provide specified technical, commercial, information system and administrative services to the Partnership for a monthly fee, until the earlier of: (i) the date on which all of the employees of the Partnership were transferred to MMH or the Partnership, or (ii) March 31, 2004; however, MMH can, at its option, extend this agreement through June 30, 2004. All of the Williams' employees assigned to the Partnership were transferred to MMH on or before January 1, 2004. MMH and Williams agreed to extend specific portions of the TSA relating to a financial system, software licenses and record storage beyond January 1, 2004. The financial system extension was terminated at the end of January 2004. The software licenses extension will terminate when all licenses are transferred to Magellan and the record storage extension will terminate in March 2004

On June 17, 2003, the Partnership entered into a new services agreement with MMH pursuant to which MMH has agreed to perform specified services, including providing necessary employees to operate our assets after the transition period described above. In return, the Partnership reimburses MMH for its direct and indirect expenses incurred in providing these services, subject to the limitations on reimbursement of general and administrative expenses discussed under the *New Omnibus Agreement* section below. MMH has the right to terminate its obligations under this new services agreement upon 90 days written notice.

New Omnibus Agreement

Also, in conjunction with the sale of Williams' interests in the Partnership, MMH, Williams and certain of Williams' affiliates entered into a new Omnibus Agreement, the terms of which include the items listed below:

- Williams and certain of its affiliates have indemnified the Partnership for covered environmental losses related to assets operated by the Partnership at the time of its initial public offering date (February 9, 2001) that become known by February 9, 2004 and that exceed amounts recovered or recoverable under the Partnership's contractual indemnities from third persons or under any applicable insurance policies. However, Williams' obligations under this indemnity are limited to $13.3 million, which represents the $15.0 million indemnity provided under the old Omnibus Agreement less amounts paid by Williams prior to June 17, 2003 under that agreement. Covered environmental losses are those non-contingent terminal and ammonia system environmental losses, costs, damages and expenses suffered or incurred by the Partnership arising from correction of violations or performance of remediation required by environmental laws in effect at February 9, 2001, due to events and conditions associated with the operation of the assets and occurring before February 9, 2001.
- Williams and certain of its affiliates have indemnified the Partnership for right-of-way defects or failures in the ammonia pipeline easements for 15 years after February 9, 2001. Williams and certain of its affiliates have also indemnified the Partnership for right-of-way defects or failures associated with the marine facilities at Galena Park and Corpus Christi, Texas and Marrero, Louisiana for 15 years after February 9, 2001.
- The Partnership will pay MMH for direct and indirect general and administrative expenses incurred on its behalf. MMH will reimburse the Partnership for general and administrative expenses subject to the limitations as described below.
  - The reimbursement obligation is subject to a lower cap amount, which is calculated as follows:
    - For the period of June 18, 2003 through December 31, 2003, MMH will reimburse the Partnership for general and administrative costs in excess of a lower cap amount of approximately $20.5 million, which represents an annual reimbursement amount of $37.9 million pro-rated for the period from June 18, 2003 through December 31, 2003;
    - For each succeeding fiscal year following 2003, the $37.9 million reimbursement amount will be 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 will also be adjusted as applicable during 2003 and subsequent periods for acquisitions, construction projects, capital improvements, replacements or expansions that the Partnership completes that are expected to increase the Partnership's general and administrative costs;
    - The reimbursement limitation expires on December 31, 2010. Additionally, the expense reimbursement limitation excludes: (i) expenses associated with equity-based incentive compensation plans and (ii) implementation costs associated with changing the name of the Partnership and expenses and capital expenditures associated with transitioning the assets, operations and employees from Williams to MMH or the Partnership.
  - The reimbursement limitation is further subject to an upper cap amount. MMH is not required to reimburse the Partnership for any general and administrative 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;

    - For each succeeding fiscal year after 2003, the upper cap will be 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 as applicable during 2003 and subsequent periods for acquisitions, construction projects, capital improvements, replacements or expansions that the Partnership completes that are expected to increase the Partnership's general and administrative costs.
  - For the twelve months immediately following the transaction close date of June 17, 2003, Williams has agreed to reimburse MMH for general and administrative expenses incurred by or on behalf of the Partnership in excess of the upper cap amount, if any.
  - For the period June 18, 2003 through December 31, 2003, the Partnership's general and administrative costs did not exceed the upper cap amount.
- Williams has agreed to reimburse the Partnership in each of the Partnership's 2003 and 2004 fiscal years for any reasonable and customary maintenance capital expenditures to maintain the assets of Magellan Pipeline, in either year, in excess of $19.0 million per year, subject to an aggregate reimbursement limitation of $15.0 million. Magellan Pipeline's maintenance capital expenditures in 2003 were less than $19.0 million.

Other Matters

- As part of its negotiations with Williams for the acquisition of the Partnership, MMH assumed Williams' obligations for $21.9 million of environmental liabilities.
- In connection with Williams' sale of its interests in the Partnership, six of the seven directors resigned from the board of directors of the General Partner and four directors affiliated with MMH were appointed to the board of the General Partner. In addition, three independent directors were appointed to the board of the Partnership's general partner during 2003. One of the independent directors appointed in 2003, George O'Brien, Jr. serves as the financial expert on the Board's Audit Committee.
- Also, subsequent to the closing of the transaction, MMH, as the holder of the Partnership's class B common units, exercised its rights under our partnership agreement to require the Partnership to solicit the approval of the Partnership's common unitholders for the conversion of the class B common units into an equal number of common units and the resulting issuance of an aggregate of 7,830,924 common units upon the conversion and cancellation of the 7,830,924 class B common units. The vote on this proposal was completed at the November 2003 annual meeting of limited partners and the class B common units were converted into an equivalent number of common units on December 1, 2003.
- Upon the closing of the transaction, MMH, as the sole member of the General Partner, entered into the Second Amendment to Limited Liability Company Agreement of the General Partner, which, among other matters, provided for the single-member status of the General Partner as of June 17, 2003. Also, upon the closing of the transaction, the Board of Directors of the General Partner and MMH adopted the Third Amendment to Limited Liability Company Agreement of the General Partner, which, among other provisions, requires the General Partner to obtain the prior approval of MMH before taking certain actions that would have or would reasonably be expected to have a direct or indirect material affect on MMH's membership interest in the General Partner. Examples of the types of matters discussed in the previous sentence are: (i) commencement of any action relating to bankruptcy or bankruptcy-related matters by the Partnership, (ii) mergers, consolidations, recapitalization or similar transactions involving the Partnership, (iii) the sale, exchange or other transfer of assets not in the ordinary course of business of a substantial portion of the assets of the Partnership, (iv) dissolution or liquidation of the Partnership, (v) material amendments of the partnership agreement, and (vi) a material change in the amount of the quarterly distribution made on the common units of the Partnership or the payment of a material extraordinary distribution.

- Upon closing of the transaction, Williams indemnified the Partnership against any environmental losses, breaches of representations and warranties, rights-of-way losses and tax matters incurred from February 9, 2001 through June 17, 2003 for assets included in the Partnership's initial public offering and from April 2002 through June 17, 2003 for Magellan Pipeline assets as well as other items not covered by Williams' preexisting indemnities of the Partnership in the amount of $175.0 million. The indemnity limitations are discussed above and in Note 17—Commitments and Contingencies.

MMH assumed sponsorship of the Magellan Pension Plan for PACE Employees ("Union Pension Plan"), previously named the Williams Pipe Line Company Pension Plan for Hourly Employees, upon transfer of the union employees from Williams to MMH on January 1, 2004. The Partnership will be required to reimburse MMH for its obligations associated with the post-retirement medical and life benefits for qualifying individuals assigned to the Partnership. The Partnership will recognize its reimbursement obligations to MMH associated with the Union Pension Plan and the post-retirement medical and life benefits over the remaining average service lives of the applicable employees (see Note 3—Summary of Significant Accounting Policies).

2. Description of Businesses

The Partnership owns and operates a petroleum products pipeline system, petroleum products terminals and an ammonia pipeline system.

Petroleum Products Pipeline System

The petroleum products pipeline system includes Magellan Pipeline, which covers an 11-state area extending from Oklahoma through the Midwest to North Dakota, Minnesota and Illinois. The system includes 6,700 miles of pipeline and 39 terminals that provide transportation, storage and distribution services. The products transported on the Magellan Pipeline system are largely petroleum products, including 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.

Petroleum Products Terminals

Most of the Partnership's 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 terminal facilities and inland terminals. Four marine terminal facilities are located along the Gulf Coast and one marine terminal facility is located in Connecticut near the New York harbor. As of December 31, 2003, we owned 23 inland terminals, which are located primarily in the southeastern United States. See Note 23—Subsequent Events for a discussion of terminal acquisitions completed after December 31, 2003.

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 for ultimate distribution to end-users in Iowa, Kansas, Minnesota, Missouri, Nebraska, Oklahoma, South Dakota and Texas. The ammonia transported through the system is used primarily as nitrogen fertilizer.

3. 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. For 11 of the petroleum products terminals, the Partnership owns varying undivided ownership interests. From inception, ownership of these assets has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other form of entity. Each owner controls marketing and invoicing separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, the Partnership applies proportionate consolidation for its interests in these assets. In January 2004, the Partnership acquired the remaining ownership interests in 8 of these terminals (see Note 23—Subsequent Events).

Reclassifications

Certain previously reported balances have been classified differently to conform with current year presentation. Net income was not affected by these reclassifications.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Regulatory Reporting

Magellan Pipeline is regulated 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. The Partnership follows generally accepted accounting principles where such differences of accounting principles exist.

Cash Equivalents

Cash and cash equivalents include demand and time deposits and other marketable securities with maturities of three months or less when acquired. The carrying amount of cash and cash equivalents approximates fair value of those instruments due to their short maturity.

Inventory Valuation

Inventory is comprised primarily of refined products, natural gas liquids and materials and supplies. Refined products and natural gas liquids inventories are stated at the lower of average cost or market. The average cost method is used for materials and supplies.

Trade Receivables

Trade receivables are recognized when products are sold or services are rendered. An allowance for doubtful accounts is established for all amounts 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 the Partnership 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 are stated at cost. Expenditures for maintenance and repairs are charged to operations in the period incurred. Depreciation of property, plant and equipment is provided on the straight-line basis. 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.

Goodwill and Other Intangible Assets

The Partnership has adopted Statement of Financial Accounting Standard ("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. The determination of whether goodwill is impaired is based on management's estimate of the fair value of the Partnership's reporting units as compared to their carrying values. If an 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.

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

Previously, goodwill was amortized on a straight-line basis over a period of 30 years for those assets acquired prior to July 1, 2001. Based on the amount of goodwill recorded as of December 31, 2001, application of the non-amortization provision of SFAS No. 142 resulted in a decrease to amortization expense in 2002 of approximately $0.8 million.

Impairment of Long-Lived Assets

In January 2002, the Partnership adopted SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets." There was no initial impact on the Partnership's results of operations or financial position upon adoption of this standard.

In accordance with this Statement, the Partnership evaluates its long-lived assets of identifiable business activities 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 an 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 an impairment were to occur, the amount of the impairment recognized would be determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if an impairment is required. 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/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

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 cost or carrying amount of the leased property is recorded as unearned income. The net investment in the lease is the difference between the gross investment and the associated unearned income.

Debt Placement Costs

Costs incurred for debt borrowings are capitalized as paid and are amortized over the life of the associated debt instrument. When debt is retired before its scheduled maturity date, the Partnership writes-off the remaining debt placement costs associated with that debt.

Capitalization of Interest

Interest on borrowed funds is capitalized on projects during construction based on the approximate average interest rate on debt owed by the Partnership. Capitalized interest for the years ended December 31, 2001, 2002 and 2003 was $0.8 million, $0.2 million and $0.1 million, respectively.

Pension and Post-Retirement Medical and Life

The Partnership has recognized affiliate pension and post-retirement medical and life obligations associated with Williams personnel, assigned to the Partnership, who became employees of MMH on or before January 1, 2004. The pension and post-retirement medical and life balances represent the funded status of the present value of benefit obligation net of unrecognized prior service cost/credits and unrecognized actuarial gains/losses.

Paid-Time Off Benefits

Affiliate liabilities for paid-time off benefits are recognized for all employees performing services for the Partnership when earned by those employees. The Partnership recognized paid-time off liability of $5.5 million at December 31, 2003 to its general partner, which represented the amount of remaining vested paid-time off benefits of dedicated employees assigned to an affiliate of the Partnership, whose role is to provide operating and general and administrative services to the Partnership.

Revenue Recognition

Magellan Pipeline transportation revenues are recognized when shipments are complete and estimated pipeline revenues are deferred for shipments in transit. Ammonia pipeline revenues are recognized when product is delivered to the customer. 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. Sales of products produced from fractionation activities and petroleum product asset management activities, are recognized upon delivery of the product to our customer.

General and Administrative Expenses

Prior to the acquisition of Williams' interests in the Partnership by MMH on June 17, 2003, the Partnership recorded general and administrative expenses up to the amount of the general and administrative expense limitation as agreed to between the Partnership, its general partner and Williams and its affiliates. Under the new organization structure put in place after June 17, 2003, the Partnership and its affiliates can now clearly identify all general and administrative costs required to support the Partnership and have recognized these costs as general and administrative expense in its current income statement. Since June 17, 2003, the amount of general and administrative expense above the expense limitation, as defined in the new Omnibus Agreement, has been recognized as a contribution of the General Partner and the associated expense specifically allocated to the General Partner.

Equity-Based Incentive Compensation Awards

The General Partner has issued incentive awards of phantom units of the Partnership to certain employees that MMH assigned to the Partnership. These awards are accounted for under provisions of Accounting Principles Board Opinion No. 25. Since the exercise price of the unit awards is less than the market price of the underlying units on the date of grant, compensation expense for the value of these awards is recognized.

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. Environmental liabilities are recorded independently of any potential claim for recovery. Receivables are recognized in cases where the realization of reimbursements of remediation costs is considered probable. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account prior remediation experience of the Partnership.

Income Taxes

Prior to February 9, 2001, the Partnership's operations were included in Williams' consolidated federal income tax return. The Partnership's income tax provisions were computed as though separate returns were filed. Deferred income taxes were computed using the liability method and were provided on all temporary differences between the financial basis and tax basis of the Partnership's assets and liabilities.

Effective with the closing of the Partnership's initial public offering on February 9, 2001 (see Note 1— Organization and Presentation), the Partnership was no longer a taxable entity for federal and state income tax purposes. Accordingly, for the petroleum products terminals and ammonia pipeline system operations, no recognition has been given to income taxes for financial reporting purposes subsequent to the initial public offering.

Prior to its acquisition by the Partnership, Magellan Pipeline was included in Williams' consolidated federal income tax return. Deferred income taxes were computed using the liability method and were provided on all temporary differences between the financial basis and the tax basis of Magellan Pipeline's assets and liabilities. Magellan Pipeline's federal provision was computed at existing statutory rates as though a separate federal tax return were filed. Magellan Pipeline paid its tax liability to Williams pursuant to its tax sharing arrangement with Williams. No recognition has been given to income taxes associated with Magellan Pipeline for financial reporting purposes for periods subsequent to its acquisition by the Partnership.

The tax on Partnership 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 the Partnership's partnership agreement. The aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in the Partnership is not available to the Partnership.

Allocation of Net Income

Net income is allocated to the General Partner and limited partners based on their respective proportional cash distributions declared and paid following the close of each quarter. The General Partner is also directly charged with specific Partnership costs that it has individually assumed and for which the limited partners are not responsible.

Earnings Per Unit

Basic earnings per unit are based on the average number of common, class B common and subordinated units outstanding. Diluted earnings per unit include any dilutive effect of phantom unit grants. Limited partners' earnings are determined after the net income allocation to the General Partner consistent with its distribution under the incentive distribution rights declared for each period presented.

Recent Accounting Standards

In December 2003, the Financial Accounting Standards Board ("FASB") issued a revision to SFAS No. 132, "Employers' Disclosures about Pensions and Other Post-Retirement Benefits". This revision requires that companies provide more details about their plan assets, benefit obligations, cash flows, benefit costs and other relevant information. A description of investment policies and strategies and target allocation percentages, or target ranges, for these asset categories also are required in financial statements. Cash flows will include projections of future benefit payments and an estimate of contributions to be made in the next year to fund pension and other post-retirement benefit plans. In addition to expanded annual disclosures, the FASB is requiring companies to report the various elements of pension and other post-retirement benefit costs on a quarterly basis. The guidance is effective for fiscal years ending after December 15, 2003, and for quarters beginning after December 15, 2003.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity". This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This Statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). Many of those instruments were previously classified as equity. This statement had no impact on the Partnership's financial position, results of operations or cash flows upon its initial adoption.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". This Statement is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. In addition all provisions of this Statement must be applied prospectively. This Statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as "derivatives") and for hedging activities under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities". The initial application of this Statement did not have a material impact on the Partnership's financial position, results of operations or cash flows upon its initial adoption.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of FASB Statement No. 123". This Statement amends FASB Statement No. 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. This Statement improves the prominence and clarity of the pro forma disclosures required by Statement 123 by prescribing a specific tabular format and by requiring disclosure in the "Summary of Significant Accounting Policies" or its equivalent. The standard is effective for fiscal periods ending after December 15, 2002. Although the Partnership accounts for stock-based compensation for employees assigned to the Partnership under provisions of Accounting Principles Board ("APB") Opinion No. 25, the structure of the awards is such that the Partnership fully recognizes compensation expense associated with unit awards. Hence, had the Partnership adopted this standard, it would not have had a material impact on the Partnership's operations or financial position.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The Partnership adopted this standard in January 2003, and it did not have a material impact on the Partnership's results of operations or financial position.

In the second quarter of 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13 and Technical Corrections". The rescission of SFAS No. 4 "Reporting Gains and Losses from Extinguishment of Debt," and SFAS No. 64, "Extinguishment of Debt Made to Satisfy Sinking-Fund Requirements," requires that gains or losses from extinguishment of debt only be classified as extraordinary items in the event they meet the criteria in APB No. 30, "Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". SFAS No. 44, "Accounting for Intangible Assets of Motor Carriers", established accounting requirements for the effects of transition to the Motor Carriers Act of 1980 and is no longer required now that the transitions have been completed. Finally, the amendments to SFAS No. 13, "Accounting for Leases", are effective for transactions occurring after May 15, 2002. All other provisions of this Statement will be effective for financial statements issued on or after May 15, 2002. The Partnership adopted this standard in January 2003, and it did not have a material impact on our results of operations or financial position. However, in subsequent reporting periods, any gains and losses from debt extinguishments will not be accounted for as extraordinary items.

4. Consolidated Statements of Cash Flows

Changes in the components of operating assets and liabilities excluding certain assets and liabilities of Magellan Pipeline which were not acquired by the Partnership (see Note 1—Organization and Presentation) are as follows (in thousands):

	Year Ended December 31, 2001	2002	2003
Accounts receivable and other accounts receivable	$ 10,393	$ (5,007)	$ (6,096)
Affiliate accounts receivable	15,758	(8,876)	3,040
Inventory	(12,919)	5,361	(6,812)
Accounts payable	2,456	4,332	3,938
Affiliate accounts payable	1,175	8,247	(9,977)
Affiliate income taxes payable	3,079	487	—
Accrued affiliate payroll and benefits	(822)	1,702	8,260
Accrued taxes other than income	(364)	3,749	589
Accrued interest payable	277	3,788	4,131
Accrued product purchases	(725)	214	8,660
Restricted cash	—	(4,942)	(3,281)
Current and noncurrent environmental liabilities	2,669	7,542	4,485
Other current and noncurrent assets and liabilities	3,548	684	5,378
Total	$ 24,525	$17,281	$12,315

5. Allocation of Net Income

The allocation of net income between the General Partner and limited partners is as follows (in thousands):

	2001	2002	2003
Allocation of net income to General Partner:			
Portion of net income applicable to partnership interest	$21,443	$85,115	$ 88,169
Direct charges to General Partner:			
Write-off of property, plant and equipment	—	—	1,788
General and administrative portion of paid-time off accrual	—	—	2,108
Transition charges	—	—	1,233
Charges in excess of the general and administrative expense cap charged against income	—	—	5,974
Total direct charges to General Partner	—	—	11,103
Income before direct charges to General Partner	21,443	85,115	99,272
General Partner's share of distributions	1.054%	5.172%	9.147%
General Partner's allocated share of net income before direct charges	226	4,402	9,081
Direct charges to General Partner	—	—	(11,103)
Net income (loss) allocated to General Partner	$ 226	$ 4,402	$ (2,022)
Portion of net income applicable to partnership interest	$21,443	$85,115	$ 88,169
Less: net income (loss) allocated to General Partner	226	4,402	(2,022)
Net income allocated to limited partners	$21,217	$80,713	$ 90,191

The write-off of property, plant and equipment relates to Magellan Pipeline's asset balances prior to its acquisition by the Partnership; hence, it is charged directly against the General Partner's allocation of net income. The general and administrative portion of the paid-time off accrual of $2.1 million during 2003 represents charges that will be reimbursed to the Partnership by the General Partner under the terms of the new Omnibus Agreement (see Note 3—Summary of Significant Accounting Policies); consequently, this amount has been charged directly against the General Partner's allocation of net income. Transition charges of $1.2 million during 2003 represent the amount of costs for transitioning the Partnership from Williams in excess of the amount contractually required to be paid by the Partnership. The Partnership recorded these excess transition costs as an equity contribution. Costs in excess of the general and administrative expense cap were $6.0 million during 2003. These amounts represent general and administrative expenses charged against Partnership income after June 17, 2003 that will be reimbursed by the General Partner to the Partnership under the terms of the new Omnibus Agreement. The Partnership has recorded the general and administrative costs in excess of the cap as an equity contribution.

6. Acquisitions and Divestitures

Magellan Pipeline

On April 11, 2002, the Partnership acquired all of the membership interests of Magellan Pipeline from an affiliate of Williams for approximately $1.0 billion. The Partnership remitted to an affiliate of Williams consideration in the amount of $674.4 million and Williams retained $15.0 million of Magellan Pipeline's receivables. The $310.6 million balance of the consideration consisted of $304.4 million of class B common units representing limited partner interests in the Partnership issued to affiliates of Williams and Williams' contribution to the Partnership of $6.2 million to maintain its 2% general partner interest. The Partnership borrowed $700.0 million from a group of financial institutions, paid an affiliate of Williams $674.4 million and used $10.6 million of the funds to pay debt fees and other transaction costs (see Note 13—Debt). The Partnership retained $15.0 million of the funds to meet working capital needs.

Magellan Pipeline primarily provides petroleum products transportation, storage and distribution services and is reported as a separate business segment of the Partnership. Because Magellan Pipeline was an affiliate of the Partnership at the time of the acquisition, the transaction was between entities under common control and, as such, has been accounted for similarly to a pooling of interest. Accordingly, the consolidated financial statements and notes of the Partnership have been restated to reflect the historical results of operations, financial position and cash flows as if the companies had been combined throughout the periods presented.

The results of operations for the separate companies and the combined amounts presented in the Consolidated Income Statement follow (in thousands):

	Years Ended December 31, 2001	2002
Revenues:		
Pre-acquisition:		
Magellan Midstream Partners	$ 86,054	$ 27,249
Magellan Pipeline	362,545	86,119
Post-acquisition:		
Magellan Midstream Partners	—	65,329
Magellan Pipeline	—	255,780
Combined	$448,599	$434,477
Net Income:		
Pre-acquisition:		
Magellan Midstream Partners	$ 21,443	$ 9,362
Magellan Pipeline	46,429	14,038
Post-acquisition:		
Magellan Midstream Partners	—	17,722
Magellan Pipeline	—	58,031
Combined	$ 67,872	$ 99,153

Because Magellan Pipeline's assets and liabilities were recorded on the Partnership's consolidated financial statements at their historical values, despite their having been acquired at market value, the General Partner's capital account was decreased by $474.5 million, which equaled the difference between the historical and market values of Magellan Pipeline. The effect of this treatment on the Partnership's overall capital balance resulted in a debt-to-total capitalization ratio of 56% and 53% at December 31, 2002 and 2003, respectively.

Other Acquisitions and Divestitures

In July 2003, the Partnership acquired certain rights to a petroleum products management operation from an affiliate of Williams for $10.1 million plus inventory costs of approximately $5.2 million. The $10.1 million acquisition costs were allocated to other intangibles and are being amortized over a 105-month period. The operating results associated with this acquisition have been included with the petroleum products pipeline system segment (see Note 16—Segment Disclosures) from the acquisition date.

During the fourth quarter of 2002, the Partnership sold its Mobile, Alabama and Jacksonville, Florida inland terminals. Total cash proceeds of approximately $1.3 million were received, with a gain of approximately $1.1 million recognized.

7. Inventory

Inventories at December 31, 2002 and 2003 were as follows (in thousands):

	December 31, 2002	December 31, 2003
Refined petroleum products	$3,863	$ 3,435
Natural gas liquids	—	12,362
Additives	897	977
Other	464	508
Total inventories	$5,224	$17,282

The increase in the natural gas liquids inventory is the result of the acquisition of certain rights and related inventories pertaining to a petroleum product management operation from an affiliate of Williams in July 2003 (see Note 6—Acquisitions and Divestitures).

8. Property, Plant and Equipment

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

	December 31, 2002	December 31, 2003	Estimated Depreciable Lives
Construction work-in-progress	$ 4,909	$ 14,657	
Land and rights-of-way	30,199	30,172	
Carrier property	898,829	893,660	6 – 59 years
Buildings	8,281	8,306	30 – 56 years
Storage tanks	172,865	178,984	30 – 40 years
Pipeline and station equipment	57,551	72,096	30 – 69 years
Processing equipment	138,180	139,724	30 years
Other	23,713	34,248	3 – 30 years
Total	$1,334,527	$1,371,847	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes capitalized interest at December 31, 2003 and 2002 of $18.1 million and $18.6 million, respectively. Depreciation expense for the years ended December 31, 2001, 2002 and 2003 was $35.2 million, $34.9 million and $35.5 million, respectively.

9. Major Customers and Concentration of Risk

No customer accounted for more than 10% of total revenues during 2002 and 2003. Williams Energy Marketing & Trading, LLC ("WEM&T"), a former affiliate customer, and Customer A accounted for more than 10% of total revenues during 2001. Customer A is and WEM&T was a customer of the petroleum products terminals segment and the petroleum products pipeline system segment. The percentage of revenues derived by customer is provided below:

	2001	2002	2003
Customer A	10%	9%	9%
WEM&T	17%	9%	2%
Total	27%	18%	11%

Accounts receivable from WEM&T accounted for 7% and 0% of total accounts and affiliate receivables at December 31, 2002 and 2003, respectively.

Magellan Pipeline transports petroleum products for refiners and marketers in the petroleum industry. The major concentration of Magellan Pipeline's revenues is derived from activities conducted in the central United States. The size and quality of the companies with which the Partnership conducts its businesses hold our credit losses to a minimum. Sales to our customers are generally unsecured and the financial condition and creditworthiness of customers are periodically evaluated. The Partnership has the ability with many of its terminals contracts to sell stored customer products to recover unpaid receivable balances, if necessary. The concentration of ammonia revenues is derived from customers with plants in Oklahoma and Texas and sales are generally unsecured. Issues impacting the petroleum refining and marketing and anhydrous ammonia industries could impact the Partnership's overall exposure to credit risk.

To conduct the Partnership's operations, an affiliate of the Partnership's general partner employes approximately 823 employees. Magellan Pipeline's labor force of 435 employees is concentrated in the central United States. At December 31, 2003, 50% of the employees were represented by a union and covered by collective bargaining agreements that extend through January 31, 2006. The petroleum products terminals operation's labor force of 174 people is concentrated in the southeastern and Gulf Coast regions of the United States. None of the terminal operations employees are represented by labor unions. The employees at the Partnership's Galena Park marine terminal facility were previously represented by a union, but indicated in 2000 their unanimous desire to terminate their union affiliation. Nevertheless, the National Labor Relations Board ("NLRB") ordered the Partnership to bargain with the union as the exclusive collective bargaining representative of the employees at the facility. Subsequently, the NLRB reversed its decision and withdrew its order. Our general partner's affiliate considers its employee relations to be good.

10. Employee Benefit Plans

On June 17, 2003, Williams sold its interest in the Partnership (see Note 1—Organization and Presentation). Employees dedicated to or otherwise supporting the Partnership 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 the Partnership for the services of the employees in accordance with the TSA as defined in Note 1 – Organization and Presentation.

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 the Partnership related to the dedicated employees' participation in the plans totaled $1.5 million, $2.9 million and $1.8 million, for the years ended December 31, 2001 and 2002, and for the period from January 1, 2003 to June 17, 2003, respectively. Expense charges from Williams to the Partnership under the transition service 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.

Employees dedicated to or otherwise supporting the Partnership also participated in a Williams defined-contribution plan. The plan provided for matching contributions within specified limits. Affiliate charges from Williams to the Partnership related to the dedicated employees' participation in the plan totaled $2.4 million, $2.3 million, and $0.7 million, for the years ended December 31, 2002 and 2001 and for the period from January 1, 2003 to June 17, 2003, respectively. Expense charges from Williams to the Partnership under the TSA related to the period from June 18, 2003 through December 31, 2003 are not specifically identifiable to the dedicated employees' participation in the plan.

The employees previously assigned by Williams to the Partnership became employees of MMH on January 1, 2004. MMH committed to provide for certain employee benefits as of the employee transfer date. The Partnership has recognized in its Consolidated Balance Sheet an obligation related to this commitment. The following table presents the Partnership's recognition of the benefit obligations and plan assets for the pension plans and other post-retirement benefit plans for which MMH assumed sponsorship or created on January 1, 2004 (in thousands):

	Pension	Other Post-Retirement Benefits
Benefit obligation	$26,294	$ 18,266
Fair value of plan assets	19,453	—
Funded status	(6,841)	(18,266)
Unrecognized prior service cost	6,841	18,266
Prepaid benefit cost	$ —	$ —
Accumulated benefit obligation	$18,252	N/A
Weighted-average assumptions used to determine benefit obligations:		
Discount rate	6.3%	6.3%
Rate of compensation increase	5.0%	N/A
Estimated contributions in 2004	$ 1,200	$ —

The Partnership used a January 1, 2004, measurement date for these plans. For benefits incurred by participants prior to age 65, the annual assumed rate of increase in the health care cost trend rate for 2004 is 8.6% and systematically decreases to 5.0% by 2009. The annual assumed rate of increase in the health care cost trend rate for post-65 benefits for 2004 is 12.0%, and systematically decreases to 5.0 % by 2016. 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
Effect on post-retirement benefit obligation	$2,428	$(1,971)

The Medicare Prescription Drug Improvement and Modernization Act of 2003 (the "Act") was enacted on December 8, 2003. The effect of the Act has not been reflected in the post-retirement benefit obligation disclosed above. Authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require the Partnership to change previously reported information.

11. Related Party Transactions

Williams' ownership interest in the Partnership was sold to MMH on June 17, 2003 (see Note 1—Organization and Presentation). As a result of that sale, transactions with Williams and its affiliates subsequent to that date were recorded as third-party transactions.

The Partnership had agreements with WEM&T which provided for: (i) the lease of a Carthage, Missouri propane storage cavern and (ii) access and utilization of storage on the Magellan Pipeline system. Magellan Pipeline had entered into pipeline lease agreements and tank storage agreements with Mid-America Pipeline

Company ("MAPL") and Williams Bio-Energy, LLC ("Williams Bio-Energy"), respectively. MAPL was an affiliate entity until its sale by Williams in July 2002 and Williams Bio-Energy was an affiliate entity until its sale by Williams in May 2003. The Partnership also had a lease storage contract with Williams Bio-Energy at its Galena Park, Texas marine terminal facility.

The Partnership also had an agreement with WEM&T, which provided for storage and other ancillary services at the Partnership's marine terminal facilities. This agreement was cancelled during the first quarter of 2003 in exchange for a $3.0 million payment to the Partnership from WEM&T. Both WEM&T and Williams Refining & Marketing had agreements for the access and utilization of the inland terminals.

The Partnership had an agreement with Williams Petroleum Services, LLC to perform services related to petroleum products asset management activities for an annual fee in 2003 of approximately $4.0 million. In July 2003, the Partnership acquired from Williams and its affiliates the rights to these activities (see Note 6—Acquisitions and Divestitures).

The Partnership also had affiliate agreements with WEM&T and Williams Refining & Marketing, LLC for the non-exclusive and non-transferable sub-license to use the ATLAS 2000 software system. The rights to this system were contributed to the Partnership on June 17, 2003 (see *Change in Ownership of General Partner* under Note 1—Organization and Presentation).

Payment terms for affiliate entity transactions were generally the same as for third-party companies. Generally, at each month-end, the Partnership was in a net payable position with Williams. The Partnership deducted any amounts owed to it by Williams before making its monthly remittances to Williams.

The following table reflects revenues from various Williams' subsidiaries through June 17, 2003 (in thousands):

	Year Ended December 31,		
	2001	2002	2003
Williams 100%-Owned Affiliates:			
Williams Energy Marketing & Trading	$75,717	$40,119	$ 7,425
Williams Refining & Marketing	13,519	8,164	306
Williams Bio-Energy	3,448	4,842	2,366
Midstream Marketing & Risk Management	—	1,719	598
Mid-America Pipeline	285	165	—
Williams Petroleum Services, LLC	—	2,625	2,992
Other	—	749	—
Williams Partially-Owned Affiliates:			
Longhorn Pipeline Partners	1,301	210	—
Rio Grande Pipeline	—	—	225
Total	$94,270	$58,593	$13,912

Costs and expenses related to activities between Williams and its affiliates and the Partnership after June 17, 2003, have been accounted for as unaffiliated third-party transactions. Transactions between the Partnership and MMH and its affiliates were accounted for as affiliate transactions after June 17, 2003. The following are costs and expenses from various affiliate companies to the Partnership and are reflected in the cost and expenses in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2001	2002	2003
Williams Energy Services—direct and directly allocable expenses	$ 29,242	$ 8,231	—
Williams—allocated general and administrative expenses	18,123	34,951	23,880
Williams—allocated operating and maintenance expenses	160,880	155,146	68,079
Williams Energy Marketing & Trading—product purchases	80,959	22,268	472
Mid-America Pipeline—operating and maintenance expenses	2,730	1,318	—
MMH—allocated operating and maintenance expenses	—	—	98,804
MMH—allocated general and administrative expenses	—	—	32,966

In 2001, 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated both direct and indirect general and administrative expenses to the Partnership's general partner. Direct expenses allocated by Williams were primarily salaries and benefits of employees and officers associated with the business activities of the affiliate. Indirect expenses include legal, accounting, treasury, engineering, information technology and other corporate services. Williams allocated these expenses to the General Partner based on the expense limitation provided for in the Omnibus Agreement. The Partnership reimbursed the General Partner and its affiliates for expenses charged to the Partnership by the General Partner on a monthly basis. On June 17, 2003, Williams' ownership in the Partnership was sold to MMH. As a result, the Partnership entered into a new services agreement with MMH pursuant to which MMH agreed to perform specified services required for the operation of the Partnership. Consequently, the Partnership's general and administrative expenses are now provided by MMH and reimbursed by the Partnership, subject to the limitations as defined in the new Omnibus Agreement (see *Change in Ownership of General Partner* under Note 1—Organization and Presentation). In addition, in 2001, 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated operating and maintenance expenses to the Partnership's general partner. Expenses included all costs directly associated with the operations of the Partnership's businesses. From June 17, 2003 through December 31, 2003 operating expenses were allocated to the Partnership's general partner from MMH.

Beginning with the closing date of the initial public offering, the General Partner, through provisions included in the Omnibus Agreement, agreed that for the assets associated with the petroleum products terminals and ammonia pipeline system operations, the Partnership would reimburse the General Partner for general and administrative costs up to a specified expense limitation. In addition, beginning with the acquisition of Magellan Pipeline, the General Partner agreed that for these assets, the Partnership would reimburse the General Partner for general and administrative costs up to a specified expense limitation. The additional general and administrative costs incurred but not reimbursed by the Partnership totaled $10.4 million for the period February 10, 2001 through December 31, 2001, $19.7 million in 2002, $5.2 million for the period January 1, 2003 through June 17, 2003 and $6.0 million for the period June 18, 2003 through December 31, 2003. The general and administrative costs allocated from Williams for the periods of February 10, 2001 through December 31, 2001, 2002 and January 1, 2003 through June 17, 2003 included a number of costs that were not specific to the Partnership's business and therefore cannot be used as an estimate of our general and administrative costs during those periods.

The Partnership and MAPL had an operating agreement whereby MAPL operated the ammonia pipeline system for the Partnership for a fee. On July 31, 2002, Williams sold 98% of Mapletree LLC, which owned

MAPL, to Enterprise Products Partners L.P. ("Enterprise"). All transactions between the Partnership, MAPL and Enterprise after July 31, 2002 have been recorded as unaffiliated third-party transactions.

Historically, Magellan Pipeline had an agreement with WEM&T to purchase transmix for fractionation and product to settle shortages. For the periods that MAPL was an affiliate of the Partnership, MAPL provided operating and maintenance support, to the ammonia pipeline and leased storage space to Magellan Pipeline.

Williams agreed to reimburse the Partnership for maintenance capital expenditures incurred in 2001 and 2002 in excess of $4.9 million per year related to our initial public offering assets. This reimbursement obligation was subject to a maximum combined reimbursement for both years of $15.0 million. During 2001 and 2002, the Partnership recorded reimbursements from Williams associated with these assets of $3.9 million and $11.0 million, respectively. In connection with our acquisition of Magellan Pipeline, Williams agreed to reimburse the Partnership for maintenance capital expenditures incurred in 2002, 2003 and 2004 in excess of $19.0 million per year related to the Magellan Pipeline system, subject to a maximum combined reimbursement for all years of $15.0 million. The Partnership's maintenance capital expenditure related to the Magellan Pipeline system in 2002 and 2003 were less than $19.0 million per year, and no amounts were collected from Williams under this agreement.

Williams and certain of its affiliates and MMH have indemnified the Partnership against certain environmental costs. Receivables from Williams or its affiliates associated with these environmental costs were $22.9 million and $7.8 million at December 31, 2002 and December 31, 2003, respectively, and are included with accounts receivable amounts presented in the Consolidated Balance Sheets. Receivables from MMH were $19.0 million at December 31, 2003 and are included with the affiliate accounts receivable in the Consolidated Balance Sheets (see Note 1—Presentation and Organization and 17—Commitments and Contingencies).

Historically, Williams charged interest expense to its affiliates based on their inter-company debt balances. The Partnership entities also participated in employee benefit plans and long-term incentive plans sponsored by Williams (see Note 10—Employee Benefit Plans).

12. Income Taxes

The Partnership does not currently pay income taxes due to its legal structure. However, earnings generated prior to the Partnership's initial public offering in 2001, and earnings of Magellan Pipeline prior to the Partnership's acquisition of it in April 2002, were subject to income taxes. The provision for income taxes is as follows (in thousands):

	Year Ended December 31,	
	2001	2002
Current:		
Federal	$19,405	$6,313
State	3,669	874
Deferred:		
Federal	5,597	987
State	841	148
	$29,512	$8,322

Reconciliations from the provision for income taxes at the U.S. federal statutory rate to the effective tax rate for the provision for income taxes are as follows (in thousands):

	Year Ended December 31,	
	2001	2002
Income taxes at statutory rate	$34,084	$ 37,616
Less: income taxes at statutory rate on income applicable to partners' interest	(7,504)	(29,790)
Increase resulting from:		
State taxes, net of federal income tax benefit	2,931	496
Other	1	—
Provision for income taxes	$29,512	$ 8,322

13. Debt

Debt for the Partnership at December 31, 2002 and 2003 was as follows (in thousands):

	December 31,	
	2002	2003
Magellan OLP term loan and revolving credit facility, long-term portion	$ 90,000	$ —
Magellan term loan and revolving credit facility:		
Long-term portion	—	89,100
Current portion	—	900
Total	—	90,000
Magellan Pipeline Senior Secured Notes, long-term portion	480,000	480,000
Total debt	$570,000	$570,000

Magellan term loan and revolving credit facility

In August 2003, the Partnership entered into a new credit agreement with a syndicate of banks. This facility, which replaced the term loan and revolving credit facility of Magellan OLP, L.P. ("Magellan OLP"), formerly Williams OLP L.P., a subsidiary of the Partnership, is comprised of a $90.0 million term loan and an $85.0 million revolving credit facility of which $10.0 million is available for letters of credit. Indebtedness under the term loan initially bore interest at the Eurodollar rate plus a margin of 2.4%. The facility was amended in December 2003 to reduce the margin on the term loan borrowings to 2.0%. Indebtedness under the revolving credit facility bears interest at the Eurodollar rate plus a margin of 1.8%. The Partnership also incurs a commitment fee on the un-drawn portion of the revolving credit facility. The facility provides for the establishment of up to $100.0 million in additional term loans, which would bear interest at a rate agreed to at the time of borrowing. The Partnership incurred debt placement fees of $2.6 million associated with this credit facility, which are being amortized over the life of the credit facility.

The new revolving credit facility terminates on August 6, 2007, and the new term loan terminates on August 6, 2008. Scheduled prepayments equal to 1.0% of the initial term loan balance are due on August 6th of each year until maturity. As of December 31, 2003, the $90.0 million term loan was outstanding with $0.2 million of the $85.0 million revolving credit facility being used for a letter of credit, with the balance available for future borrowings. Obligations under the facility are secured by the Partnership's equity interests in Magellan GP, Inc. and Magellan OLP and their subsidiaries, including the entities which hold our petroleum products terminals and ammonia pipeline system. Magellan GP, Inc., a Delaware corporation, is the general partner of Magellan OLP. Those entities are also guarantors of the Partnership's obligations under the facility. Magellan Pipeline is a separate operating subsidiary of the Partnership and is not a guarantor under this facility. The weighted-average interest rate for this facility for the period August 6, 2003 through December 31, 2003 was 3.4% and the interest rate at December 31, 2003 was 3.2%.

Under the terms of the above-named facility, a change in control results in an event of default, in which case the maturity date of the obligations under the facility may be accelerated. For this facility, a change of control is defined in a variety of ways, each of which involve the current owners of MMH no longer maintaining majority control of the management of MMH, the Partnership or the General Partner. This facility contains various operational and financial covenants. The Partnership is in compliance with all of these covenants.

At December 31, 2002, Magellan OLP, had a $175.0 million bank credit facility which was comprised of a $90.0 million term loan facility and an $85.0 million revolving credit facility. On February 9, 2001, the OLP borrowed $90.0 million under the term loan facility, which remained outstanding until August 2003, when the facility was repaid. Borrowings under the credit facility carried an interest rate equal to the Eurodollar rate plus a spread from 1.0% to 1.5%, depending on the OLP's leverage ratio. Interest was also assessed on the unused portion of the credit facility at a rate from 0.2% to 0.4%, depending on the OLP's leverage ratio. Closing fees associated with the initiation of the credit facility were $0.9 million and were amortized over the life of the facility. Weighted-average interest rates were 5.0% for the period February 10, 2001 through December 31, 2001, 3.3% for the twelve months ended December 31, 2002 and 2.6% for the period January 1, 2003 through August 6, 2003 (when the facility was repaid). The interest rates for amounts borrowed against this facility on December 31, 2001 and 2002 were 3.2% and 2.8%, respectively.

Magellan Pipeline Senior Secured Notes

During October 2002, Magellan Pipeline entered into a private placement debt agreement with a group of financial institutions for up to $200.0 million aggregate principal amount of Floating Rate Series A-1 and Series A-2 Senior Secured Notes and up to $340.0 million aggregate principal amount of Fixed Rate Series B-1 and Series B-2 Senior Secured Notes. Both notes are secured with the Partnership's membership interest in and assets of Magellan Pipeline. The maturity date of both notes is October 7, 2007; however, the Partnership will be required on each of October 7, 2005 and October 7, 2006, to repay 5.0% of the then outstanding principal amount of the Senior Secured Notes. Two borrowings have occurred in relation to these notes. The first borrowing was completed in November 2002 and was for $420.0 million, of which $156.0 million was borrowed under the Series A-1 notes and $264.0 million under the Series B-1 notes. The proceeds from this initial borrowing were used to repay Williams Pipe Line's $411.0 million short-term loan and pay related debt placement fees. The second borrowing was completed in December 2002 for $60.0 million, of which $22.0 million was borrowed under the Series A-2 notes and $38.0 million under the Series B-2 notes. $58.0 million of the proceeds from this second borrowing were used to repay the acquisition sub-facility of the OLP and $2.0 million were used for general partnership purposes.

The Series A-1 and Series A-2 notes bear interest at a rate equal to the six month Eurodollar rate plus 4.3%. The Series B-1 notes bear interest at a fixed rate of 7.7%, while the Series B-2 notes bear interest at a fixed rate of 7.9%. The weighted-average rate for the Magellan Pipeline Senior Secured Notes at December 31, 2003 and 2002 was 6.9% and 7.0%, respectively. The Partnership incurred debt placement fees associated with these notes of $10.5 million in 2002 and $0.3 million in 2003, which are being amortized over the life of the notes. Payment of interest and repayment of the principal is guaranteed by the Partnership. Monthly deposits in the amount of interest due the lenders are made to a cash escrow account from which interest payments on the Magellan Pipeline notes are made semi-annually. These deposits are reflected as restricted cash on the Partnership's Consolidated Balance Sheets and were $4.9 million and $8.2 million at December 31, 2002 and 2003, respectively.

The debt agreement imposes certain restrictions on Magellan Pipeline and the Partnership. Generally, the agreement restricts the amount of additional indebtedness Magellan Pipeline can incur, prohibits Magellan Pipeline from creating or incurring any liens on its property, and restricts Magellan Pipeline from disposing of its property, making any debt or equity investments, or making any loans or advances of any kind. The agreement also requires transactions between Magellan Pipeline and any of its affiliates to be on terms no less favorable than those Magellan Pipeline would receive in an arms-length transaction. In the event of a change in control of the General Partner, each holder of the notes would have thirty days within which they could exercise a right to put their notes to Magellan Pipeline unless the new owner of the General Partner has (i) a net worth of at least $500.0 million and (ii) long-term unsecured debt rated as investment grade by both Moody's Investor Service Inc. and Standard & Poor's Rating Service. If this put right were exercised, Magellan Pipeline would be obligated to repurchase any such notes and repay any accrued interest within sixty days.

In April 2002, the Partnership borrowed $700.0 million from a group of financial institutions. This short-term loan was used to help finance the Partnership's acquisition of Magellan Pipeline. During the second quarter of 2002 the Partnership repaid $289.0 million of the short-term loan with net proceeds from an equity offering. Debt placement fees associated with the note were $7.1 million and were amortized over the life of the note. In October 2002, the Partnership negotiated an extension to the maturity of this note from October 8, 2002, to November 27, 2002 and the Partnership paid additional fees of approximately $2.1 million associated with this maturity date extension. The Partnership repaid the remaining outstanding balance of the note on November 15, 2002. The weighted-average interest rate on this note was 5.1% for the period April 11, 2002 through November 15, 2002.

During September 2002, in anticipation of a new debt placement to replace the short-term debt assumed to acquire Magellan Pipeline, the Partnership entered into an interest rate hedge. The effect of this interest rate hedge was to set the coupon rate on a portion of the fixed-rate debt at 7.8% prior to actual execution of the debt agreement. The loss on the hedge, approximately $1.0 million, was recorded in accumulated other comprehensive loss and is being amortized over the five-year life of the fixed-rate debt secured during October 2002.

During the years ending December 31, 2001, 2002 and 2003, total cash payments for interest on all indebtedness, net of amounts capitalized, were $13.7 million, $18.0 million and $32.5 million, respectively.

14. Leases

Leases—Lessee

The Partnership leases land, office buildings, tanks and terminal equipment at various locations to conduct its business operations. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2003, are as follows (in thousands):

2004	$ 2,435
2005	2,290
2006	2,215
2007	2,167
2008	1,661
Thereafter	7,740
Total	$18,508

Leases—Lessor

On December 31, 2001, the Partnership 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. The Partnership then entered into a long-term lease arrangement under which Aux Sable is the sole lessee of these assets. The Partnership has 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. The Partnership also has two five-year pipeline capacity leases with Farmland Industries, Inc. The first agreement, which is accounted for as a direct financing lease, will expire on November 30, 2005 and the second agreement, which is accounted for as an operating lease, will expire on April 30, 2007. Both leases contain options to extend the agreement for another five years. In addition, the Partnership has nine other capacity operating leases with terms of one to thirteen years. All of the agreements provide for negotiated extensions.

Future minimum lease payments receivable under operating-type leasing arrangements as of December 31, 2003, are as follows (in thousands):

2004	$ 8,336
2005	4,904
2006	4,372
2007	4,062
2008	3,907
Thereafter	19,172
Total	$44,753

Future minimum lease payments receivable under direct-financing-type leasing arrangements as of December 31, 2003, were $2.5 million in 2004, $1.3 million during each year from 2005 through 2008 and $10.1 million cumulatively for all periods after 2008. The net investment under direct financing leasing arrangements as of December 31, 2002 and 2003, are as follows (in thousands):

	December 31,	
	2002	2003
Total minimum lease payments receivable	$20,154	$17,699
Less: Unearned income	9,923	8,469
Recorded net investment in direct financing leases	$10,231	$ 9,230

As of December 31, 2003, the net investment in direct financing leases is classified in the Consolidated Balance Sheet as $0.4 million current accounts receivable, $0.2 million current deferred revenue and $9.0 million noncurrent receivable. As of December 31, 2002, the net investment in direct financing leases is classified in the Consolidated Balance Sheet as $1.4 million current accounts receivable, $0.4 million current deferred revenue, $9.4 million non-current receivable and $0.2 non-current deferred revenue.

15. Long-Term Incentive Plan

In February 2001, the General Partner adopted the Williams Energy Partners' Long-Term Incentive Plan, which was amended and restated on February 3, 2003, on July 22, 2003, and on February 3, 2004, for employees who perform services for the Partnership and directors of the 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 700,000 common units. The Compensation Committee of the General Partner's Board of Directors administers the Long-Term Incentive Plan.

In April 2001, the General Partner issued grants of 92,500 phantom units to certain key employees associated with the Partnership's initial public offering in February 2001. These awards allowed for early vesting if established performance measures were met prior to February 9, 2004. The Partnership met all of these performance measures and all of the awards vested during 2002. The Partnership recognized compensation expense of $0.7 million and $2.1 million associated with these awards in 2001 and 2002, respectively.

In April 2001, the General Partner granted 64,200 phantom units pursuant to the Long-Term Incentive Plan. With the change in control of the General Partner, which occurred on June 17, 2003, these awards vested at their maximum award level, resulting in 128,400 unit awards. The Partnership elected to settle these awards with cash payments instead of common units. The Partnership recognized compensation expense associated with these awards of $1.3 million, $1.5 million and $3.4 million during 2001, 2002 and 2003, respectively.

During 2002, the General Partner granted 22,650 phantom units pursuant to the Long-Term Incentive Plan. With the change in control of the General Partner, which occurred on June 17, 2003, these awards vested at their maximum award level, resulting in 45,300 unit awards. The Partnership elected to settle these awards with cash payments instead of common units. The Partnership recognized compensation expense associated with these awards of $0.2 million and $2.0 million in 2002 and 2003, respectively.

In February 2003, the General Partner granted 52,825 phantom units pursuant to the Long-Term Incentive Plan. The actual number of units that will be awarded under this grant are based on certain performance metrics, which were determined by the Partnership at the end of 2003, and a personal performance component that will be determined at the end of 2005, with vesting to occur at that time. Because 3,080 unit grants vested early (see discussion below), the remaining number of units that could be awarded, excluding the personal performance component will range from zero units up to a total of 99,490 units. These units are subject to forfeiture if employment is terminated prior to the vesting date. These awards do not have an early vesting feature, except for: (i) the death or disability of a participant, or (ii) a change in control of the Partnership's general partner where the participant is terminated for reasons other than cause within the two years following the change in control of the General Partner, in which case the awards will vest and payout immediately at the highest performance level under the Plan. Subsequent to the change in control of the General Partner on June 17, 2003, certain awards under this grant vested at their maximum award level (two times the original grant), resulting in a cash payout associated with 6,160 unit awards. Until the payout of these awards, the Partnership was expensing compensation costs associated with the non-vested portion of these awards assuming 52,825 units would vest. Subsequent to the vesting of 6,160 awards previously mentioned, the Partnership began accruing compensation expense assuming 49,745 units would vest; however, during 2003, the Partnership increased the associated accrual to an expected payout of 95,271 units. Accordingly, the Partnership recorded incentive compensation expense of $1.7 million associated with these awards during 2003. The value of the 95,271 unit awards on December 31, 2003 was $4.8 million.

In October 2003, the General Partner granted 10,640 phantom units pursuant to the Long-Term Incentive Plan. Of these awards, 4,850 units vested on December 31, 2003. The remaining units will vest as follows: 470 units on July 31, 2004, 4,850 units on December 31, 2004 and 470 units on July 31, 2005. There are no performance metrics associated with these awards and the payouts cannot exceed the face amount of the units awarded. These units are subject to forfeiture if employment is terminated prior to the vesting date. These awards do not have an early vesting feature, except for: (i) the death or disability of a participant, or (ii) a change in control of the Partnership's general partner where the participant is terminated for reasons other than cause or the employee voluntarily terminates for good reason within the two years following the change in control of the General Partner. The Partnership recorded $0.3 million of compensation expense associated with these awards during 2003. The value of the 5,790 unvested awards at December 31, 2003 was $0.3 million.

Our equity-based incentive compensation costs for 2001, 2002 and 2003 are summarized as follows (in millions):

	2001	2002	2003	Total
IPO awards	$ 0.7	$ 2.1	$ —	$ 2.8
2001 awards	1.3	1.5	3.4	6.2
2002 awards	—	0.2	2.0	2.2
2003 awards	—	—	2.0	2.0
Total	$ 2.0	$ 3.8	$ 7.4	$13.2

16. Segment Disclosures

Management evaluates performance based upon segment operating margin, which includes revenues from affiliate and external customers, operating expenses, environmental expense and environmental reimbursements. The accounting policies of the segments are the same as those described in Note 3—Summary of Significant Accounting Policies.

On June 17, 2003, Williams sold its interest in the Partnership to MMH. Prior to June 17, 2003, affiliate revenues from Williams were accounted for as if the sales were to unaffiliated third parties. Subsequent to June 17, 2003, the Partnership had no affiliate revenues. Also, prior to June 17, 2003, affiliate general and administrative 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, all affiliate general and administrative costs were charged to the Partnership and allocated to the business segments based on a three-factor formula which considers total salaries, property, plant and equipment and operating revenue less cost of sales.

The Partnership's 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. Operating expenses and depreciation and amortization do not agree with the reported amounts on the income statements for the 2003 period due to the allocation of corporate depreciation charges to the segments as an operating expense.

	Twelve Months Ended December 31, 2003			
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Total
	(in thousands)			
Revenues:				
Third-party customers	$381,094	$ 77,546	$12,608	$ 471,248
Affiliate customers	7,906	6,006	—	13,912
Total revenues	389,000	83,552	12,608	485,160
Operating expenses	126,246	34,677	4,562	165,485
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	217,497
Depreciation and amortization	22,320	11,804	1,084	35,208
Affiliate general and administrative 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, the Partnership recorded a $5.5 million liability for paid-time off benefits associated with the employees supporting the Partnership. These costs, charged to 2003 operating and affiliate general and administrative expenses, resulted from MMH's acquisition of the Partnership and the Partnership's subsequent assumption of MMH's employee-related liabilities. These costs were charged to the Partnership's 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 general and administrative 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 the Partnership to MMH, the Partnership was responsible for $5.9 million of costs to separate from Williams. Of these costs, $3.7 million was charged to affiliate general and administrative 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.

	Twelve Months Ended December 31, 2002			
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Total
	(in thousands)			
Revenues:				
Third-party customers	$299,875	$ 62,874	$13,135	$ 375,884
Affiliate customers	42,024	16,569	—	58,593
Total revenues	341,899	79,443	13,135	434,477
Operating expenses	112,346	35,619	4,867	152,832
Environmental	17,514	(788)	88	16,814
Environmental reimbursements	(15,176)	768	(92)	(14,500)
Product purchases	63,982	—	—	63,982
Operating margin	163,233	43,844	8,272	215,349
Depreciation and amortization	22,992	11,447	657	35,096
Affiliate general and administrative expenses	32,779	8,921	1,482	43,182
Segment profit	$107,462	$ 23,476	$ 6,133	$ 137,071
Segment assets	$647,771	$346,221	$37,646	$1,031,638
Corporate assets				88,721
Total assets				$1,120,359
Goodwill	—	22,295	—	22,295
Additions to long-lived assets	16,013	20,792	443	37,248

	Twelve Months Ended December 31, 2001			
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Total
	(in thousands)			
Revenues:				
Third-party customers	$284,174	$ 55,611	$14,544	$ 354,329
Affiliate customers	78,371	15,899	—	94,270
Total revenues	362,545	71,510	14,544	448,599
Operating expenses	116,080	33,170	3,807	153,057
Environmental	7,486	3,477	596	11,559
Environmental reimbursements	—	(3,377)	(359)	(3,736)
Product purchases	95,268	—	—	95,268
Operating margin	143,711	38,240	10,500	192,451
Depreciation and amortization	24,019	11,099	649	35,767
Affiliate general and administrative expenses	38,410	7,641	1,314	47,365
Segment profit	$ 81,282	$ 19,500	$ 8,537	$ 109,319
Segment assets	$705,115	$354,579	$31,035	$1,090,729
Corporate assets				13,830
Total assets				$1,104,559
Goodwill	—	22,282	—	22,282
Additions to long-lived assets	24,232	64,590	330	89,152

17. Commitments and Contingencies

Williams has agreed to indemnify the Partnership against any covered environmental losses up to $15.0 million relating to assets it contributed to the Partnership at the time of the initial public offering. We refer to this indemnity in the table below as the "IPO Indemnity". See *Change in Ownership of General Partner* in Note 1 for details regarding this indemnity. That same section of Note 1 further describes certain right-of-way indemnities associated with the ammonia pipeline easements and right-of-way defects or failures associated with the marine terminal facilities at Galena Park and Corpus Christi, Texas and Marrero, Louisiana.

In connection with the acquisition of Magellan Pipeline, Williams agreed to indemnify the Partnership for any breaches of representations or warranties, environmental liabilities and failures to comply with environmental laws as described below that result in losses and damages up to $110.0 million after the payment of an applicable $2.0 million deductible. With respect to any amount exceeding $110.0 million, Williams will be responsible for one-half of that amount up to $140.0 million. Williams' liability under this indemnity is capped at $125.0 million. We refer to this indemnity in the table below as the "Magellan Pipeline Indemnity". This indemnification obligation survived for one year, except for those obligations relating to employees, title, taxes and environmental. Obligations relating to employees and employee benefits will survive for the applicable statute of limitations and those obligations relating to real property, including asset titles, will survive for ten years after April 11, 2002, the date the Partnership acquired Magellan Pipeline. This indemnity also provides that the Partnership will be indemnified for an unlimited amount of losses and damages related to tax liabilities. In addition, any losses and damages related to environmental liabilities caused by events that occurred prior to the acquisition and for which claims are made within six years of the Partnership's acquisition of Magellan Pipeline will be subject to a $2.0 million deductible, which was met during 2002. Covered environmental losses include those losses arising from the correction of violations of, or performance of remediation required by, environmental laws in effect at April 11, 2002.

Williams has also indemnified the Partnership against environmental losses that occurred from February 2001 through June 17, 2003 for assets included in the Partnership at the time of its initial public offering and from April 2002 through June 17, 2003 for Magellan Pipeline assets as well as other items not covered by Williams' preexisting indemnifications of the Partnership. See *Change in Ownership of General Partner* under Note 1—Organization and Presentation for additional discussion of this matter. We refer to this indemnity in the table below as the "Acquisition Indemnity".

	Maximum Indemnity Amount	Claims Against Indemnity	Amount of Indemnity Remaining
IPO Indemnity	$ 15.0	$ 3.4	$ 11.6
Magellan Pipeline Indemnity	125.0	18.0	107.0
Acquisition Indemnity	175.0	0.7	174.3
Total	$315.0	$22.1	$292.9

Estimated liabilities for environmental costs were $22.3 million and $26.8 million at December 31, 2002 and 2003, respectively. These estimates, provided on an undiscounted basis, were determined based primarily on data provided by a third-party environmental evaluation service and internal environmental personnel. These liabilities 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 five to ten years. As described in *Change in Ownership of General Partner* under Note 1, MMH assumed Williams' obligations for $21.9 million of environmental liabilities, and the Partnership recorded a receivable from MMH for this amount. MMH reduced the amount it paid for Williams' ownership interest in the Partnership by the present value of the cash flows associated with the $21.9 million of environmental liabilities. To the extent the environmental and other Williams indemnity claims against MMH are not $21.9 million and to the extent no other indemnity obligations exist with Williams, MMH will pay to Williams the remaining difference between $21.9 million and the indemnity claims paid by MMH. Receivables from Williams or its affiliates associated with indemnified environmental costs were $7.8 million at December 31, 2003 and $22.9 million at December 31, 2002, and receivables from MMH at December 31, 2003 were $19.0 million. The Partnership invoices MMH, Williams and its affiliates or other third-party entities for its environmental indemnities as remediation work is performed.

In conjunction with the 1999 acquisition of the Gulf Coast marine terminals from Amerada Hess Corporation ("Hess"), Hess represented that it has disclosed to the Partnership all suits, actions, claims, arbitrations, administrative, governmental investigation or other legal proceedings pending or threatened, against or related to the assets acquired by the Partnership, which arise under environmental law. In the event that any pre-acquisition releases of hazardous substances at the Partnership's Corpus Christi and Galena Park, Texas and Marrero, Louisiana marine terminal facilities were unknown at closing but subsequently identified by the Partnership prior to July 30, 2004, the Partnership will be liable for the first $2.5 million of environmental liabilities, Hess will be liable for the next $12.5 million of losses and the Partnership will assume responsibility for any losses in excess of $15.0 million subject to Williams' indemnities to the Partnership. Also, Hess agreed to indemnify the Partnership through July 30, 2014 against all known and required environmental remediation costs at the Corpus Christi and Galena Park, Texas marine terminal facilities from any matters related to pre-acquisition actions. Hess has indemnified the Partnership for a variety of pre-acquisition fines and claims that may be imposed or asserted against the Partnership under certain environmental laws.

During 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act, preliminarily determined that Williams may have systemic problems with petroleum discharges from pipeline operations. The inquiry primarily focused on Magellan Pipeline. The response to the EPA's information request was submitted during November 2001. The EPA has recently informed us that they have initiated a review of the response submitted in 2001. The Partnership believes any claims the EPA may assert relative to this inquiry is covered by Williams' indemnifications to the Partnership.

During the fourth quarter of 2003, the Partnership experienced a line break and product spill on its petroleum products pipeline near Shawnee, Kansas, which resulted in the Partnership recognizing environmental liabilities of $4.3 million. The Partnership recorded a receivable from its insurance carrier of $2.6 million associated with this spill. This break occurred in a section of line near a previous break site that had been remediated by Williams. The Partnership believes the current break is covered by indemnifications from Williams and has filed a claim against Williams for the total amount of the estimated liability associated with this spill. Williams is currently evaluating our claim.

The Partnership is party to various other claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, the ultimate resolution of all claims, legal actions and complaints after consideration of amounts accrued insurance coverage or other indemnification arrangements will not have a material adverse effect upon the Partnership's future financial position, results of operations or cash flows.

18. Quarterly Financial Data (unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2003				
Revenues	$119,715	$107,925	$122,176	$135,344
Total costs and expenses	81,605	79,833	90,329	107,950
Net income	29,058	18,859	22,271	17,981
Basic net income per limited partner unit	0.99	0.75	0.84	0.73
Diluted net income per limited partner unit	0.99	0.75	0.84	0.73
2002				
Revenues	$102,648	$104,124	$113,376	$114,329
Total costs and expenses	73,896	67,433	79,077	77,000
Net income	21,126	24,628	25,833	27,566
Basic net income per limited partner unit	0.73	1.05	0.90	0.95
Diluted net income per limited partner unit	0.72	1.05	0.90	0.95

First-quarter 2003 results were favorably impacted by a $3.0 million contract settlement. Second-quarter 2003 results included the impact of costs associated with the change in the Partnership's general partner which included: (i) paid-time off accruals of $4.9 million, early vesting of equity-based incentive compensation awards of $2.9 million and transition costs of $0.6 million. Third-quarter 2003 results included $1.4 million of transition costs. Fourth quarter 2003 results included $1.8 million of pipeline remediation costs associated with a product spill, $2.3 million of transition costs and $1.6 million of asset write-offs.

Basic and diluted net income for the second, third and fourth quarters of 2002 include the impact of the Partnership's ownership of Magellan Pipeline. Fourth quarter 2002 net income included a gain of $1.1 million on the sale of the inland terminals. Second, third and fourth quarter net income for 2002 was impacted by the amortization of debt placement costs of $7.1 million associated with the short-term note assumed at the time of the Magellan Pipeline acquisition by the Partnership and interest expense associated with that note. Fourth quarter results were impacted by the amortization of the $2.1 million debt placement costs associated with the extension of the maturity date of the Magellan short-term note and interest expense on the new $480.0 million borrowings by Magellan Pipeline.

19. Fair Value of Financial Instruments

The following methods and assumptions were used by the Partnership in estimating its 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 of these instruments.

Long-term affiliate receivables: Fair value is determined by discounting estimated cash flows by the Partnership's 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.

Long-term debt: During 2002, the Partnership had all variable-rate debt until late in the year, when part of the debt was replaced with fixed-rate debt, consequently, the carrying amount of debt approximated fair value at December 31, 2002. For 2003, the carrying amount of the Partnership's variable-rate debt approximates fair value and the fair value of the Partnership's fixed-rate debt was determined by discounting estimated future cash flows using the Partnership's incremental borrowing rate.

The following table reflects the carrying amounts and fair values of the Partnership's financial instruments as of December 31, 2002 and 2003 (in thousands):

	December 31, 2002		December 31, 2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 75,151	$ 75,151	$111,357	$111,357
Restricted cash	4,942	4,942	8,223	8,223
Long-term affiliate receivables	11,656	9,716	13,472	11,408
Long-term receivables	9,268	7,910	9,077	8,032
Long-term debt	570,000	570,000	570,000	577,510

20. Distributions

Distributions paid by the Partnership during 2001, 2002 and 2003 are as follows (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 Equivalent Units	Total Cash Distribution
05/15/01(a)	$0.2920	$ 1,658	$ 1,658	$ —	$ 69	$ 3,385
08/14/01	0.5625	3,195	3,195	—	130	6,520
11/14/01	0.5775	3,281	3,281	—	132	6,694
Total	$1.4320	$ 8,134	$ 8,134	$ —	$ 331	$16,599
02/14/02	$0.5900	$ 3,351	$ 3,351	$ —	$ 159	$ 6,861
05/15/02	0.6125	3,479	3,479	—	204	7,162
08/14/02	0.6750	9,234	3,834	5,286	868	19,222
11/14/02	0.7000	9,576	3,978	5,482	1,092	20,128
Total	$2.5775	$25,640	$14,642	$10,768	$2,323	$53,373
02/14/03	$0.7250	$ 9,918	$ 4,118	$ 5,677	$1,321	$21,034
05/15/03	0.7500	10,260	4,260	5,873	1,548	21,941
08/14/03	0.7800	10,670	4,430	6,108	1,820	23,028
11/14/03	0.8100	11,081	4,601	6,343	2,499	24,524
Total	$3.0650	$41,929	$17,409	$24,001	$7,188	$90,527

(a) This distribution represented the prorated minimum quarterly distribution for the 50-day period following the initial public offering closing date, which included February 10, 2001 through March 31, 2001.

On February 13, 2004, the Partnership paid cash distributions of $0.83 per unit on its outstanding common and subordinated units to unitholders of record at the close of business on February 6, 2004. The total distribution, including distributions paid to the General Partner on its equivalent units, was $25.8 million.

21. 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	27,195	$3.32
Effect of dilutive restrictive unit grants	—	40	.01
Diluted net income per limited partner unit	$90,191	27,235	$3.31

	For The Year Ended December 31, 2002		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$80,713		
Basic net income per limited partner unit	$80,713	21,911	$3.68
Effect of dilutive restrictive unit grants	—	57	0.01
Diluted net income per limited partner unit	$80,713	21,968	$3.67

	For The Year Ended December 31, 2001		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income applicable to the period after February 9, 2001	$21,217		
Basic net income per limited partner unit	$21,217	11,359	$1.87
Effect of dilutive restrictive unit grants	—	11	—
Diluted net income per limited partner unit	$21,217	11,370	$1.87

Units reported as dilutive securities are related to restricted unit grants associated with the one-time initial public offering award (see Note 15—Long-Term Incentive Plan).

22. Partners' Capital

Of the 21,710,618 common units outstanding at December 31, 2003, the public holds 17,775,000, with the remaining 3,935,618 held by affiliates of the Partnership. All of the 5,679,694 subordinated units are held by affiliates of the Partnership. The 7,830,924 class B common units that were outstanding at December 31, 2002, were converted to common units during 2003.

During the subordination period, the Partnership can issue up to 2,839,847 additional common units without obtaining unitholder approval. In December 2003, the Partnership issued 200,000 units to the public, which reduced the number of additional common units it can issue without unitholder approval to 2,639,847. The General Partner can issue an unlimited number of common units as follows:

- upon exercise of the underwriters' over-allotment option;
- upon conversion of the subordinated units;
- under employee benefit plans;

- upon conversion of the general partner interest and incentive distribution rights as a result of a withdrawal of the General Partner;
- in the event of a combination or subdivision of common units;
- in connection with an acquisition or a capital improvement that increases cash flow from operations per unit on a pro forma basis; or
- if the proceeds of the issuance are used exclusively to repay up to $40.0 million of our indebtedness.

The subordination period will end when the Partnership meets certain financial tests provided for in the Partnership agreement but it generally cannot end before December 31, 2005.

The limited partners holding common units of the Partnership have the following rights, among others:

- right to receive distributions of the Partnership's available cash within 45 days after the end of each quarter;
- right to elect the board members of the Partnership's general partner;
- right to remove Magellan GP, LLC as the 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 the Partnership on any meeting that may be called by the General Partner; and
- right to inspect our books and records at the unitholders' own expense.

Net income is allocated to the General Partner and limited partners based on their proportionate share of cash distributions for the period. Cash distributions to the General Partner and limited partners are made based on the following table:

	Percentage of Distributions	
Quarterly Distribution Amount (per unit)	**Limited Partners**	**General Partner**
Up to $0.578	98	2
Above $0.578 up to $0.656	85	15
Above $0.656 up to $0.788	75	25
Above $0.788	50	50

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.

23. Subsequent Events

In January 2004, the underwriters exercised their over-allotment option associated with MMH's unit offering completed in December 2003. As a result, MMH sold an additional 675,000 common units that they held of the Partnership, with all of the proceeds from this sale going to MMH.

On January 29, 2004, the Partnership announced that it had acquired ownership in 14 refined petroleum products terminals located in the southeastern United States for $24.8 million. The partnership previously owned a 79% interest in eight of these terminals and purchased the remaining interest from Murphy Oil USA, Inc. In addition, the acquisition includes sole ownership of six terminals that were previously jointly owned by Murphy Oil USA, Inc. and Colonial Pipeline Company.

On February 13, 2004, the Partnership paid cash distributions of $0.83 per unit on its outstanding common and subordinated units to unitholders of record at the close of business on February 6, 2004. The total distribution was approximately $25.8 million.

Also, associated with the declaration and payment of the cash distributions in February 2004, 25% of the partnership's subordinated units, or 1,419,923 units, converted to common units on the record date of February 6, 2004. Magellan's partnership agreement provides for the conversion because quarterly distributions have equaled or exceeded the Partnership's $0.525 per unit minimum quarterly distribution for three consecutive years.

In February 2004, the Partnership entered into three separate agreements with two different banks for forward interest rate swaps totaling $150.0 million. The swaps begin in October 2007, when the Partnership expects to refinance the majority of Magellan Pipeline's $480.0 million senior secured notes. Under the swap agreements, the Partnership will pay fixed interest rates and will receive LIBOR in return for a ten-year period, which is the assumed tenure of replacement debt. The average fixed rate on the swap is 5.9%.

On March 2, 2004, the Partnership acquired a 50% ownership in Osage Pipe Line Company, LLC, which owns the Osage pipeline, for $25.0 million from National Cooperative Refinery Association ("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. The remaining 50% interest in the Osage Pipe Line Company, LLC will continue to be owned by NCRA.

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

None

ITEM 9A. *Controls and Procedures*

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) 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.

The Partnership's management, including the General Partner's Chief Executive Officer and Chief Financial Officer, does not expect that the Partnership's disclosure controls or its internal controls over financial reporting (internal controls) 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 breakdowns can occur because of simple error or mistake. 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. The Partnership monitors its disclosure controls and internal controls and makes modifications as necessary; the Partnership's intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

We have furnished as a correspondence filing to the Securities and Exchange Commission the certifications of this report by the General Partner's Chief Executive Officer and Chief Financial Officer as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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 will be presented in our proxy statement prepared for the solicitation of proxies in connection with our Annual Meeting of Limited Partners for 2004 (our "Proxy Statement") under the captions "Names and Business Experience of the Class II Nominees and Other Directors" and "Executive Officers of our General Partner", which information is incorporated by reference herein. Information required by Item 405 of Regulation S-K will be presented under the caption "Compliance with Section 16(a) of the Exchange Act" in our Proxy Statement, which information is incorporated by reference herein. Information required by Item 406 of Regulation S-K will be 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 will be 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 will be 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 will be 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 will be 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 will be presented in our Proxy Statement under the caption "Independent Public Accountants", which information is incorporated by reference herein.

PART IV

ITEM 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(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).

Exhibit No.	Description
*(b)	—Amendment No. 1 dated May 5, 2003 to 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 99.2 to Schedule 13D/A filed June 20, 2003).
(c)	Amendment No. 2 dated January 6, 2004, to Purchase Agreement dated April 18, 2003, among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P.
Exhibit 3	
*(a)	—Certificate of Limited Partnership of Williams Energy Partners L.P. dated August 30, 2000, as amended on November 15, 2002 and August 12, 2003 (filed as Exhibit 3.1 to Form 10-Q filed November 10, 2003).
*(b)	—Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated September 30, 2002 (filed as Exhibit 10.3 to Form 10-Q filed November 14, 2002).
*(c)	—Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated November 15, 2002 (filed as Exhibit 3.1 to Form 8-K filed November 19, 2002).
*(d)	—Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated November 15, 2002 (filed as Exhibit 3.2 to Form 8-K filed November 19, 2002).
(e)	—Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated December 12, 2003.
(f)	—Amended and Restated Certificate of Formation of WEG GP LLC dated November 15, 2002, as amended on August 12, 2003.
(g)	—Amended & Restated Limited Liability Company Agreement of Magellan GP, LLC dated December 1, 2003.
(h)	—Amendment No. 1 dated February 3, 2004 to Amended & Restated Limited Liability Company Agreement of Magellan GP, LLC dated December 1, 2003.
*(i)	—Reorganization Agreement dated March 4, 2002, among Williams Energy Partners L.P., Williams OLP, L.P., Williams GP LLC and Williams GP Inc. (filed as Exhibit 3(d) to Form 10-K filed March 7, 2002).
*(j)	—Contribution Agreement dated April 11, 2002 between Williams Energy Partners L.P., Williams GP LLC and Williams Energy Services, LLC (filed as Exhibit 10 to Form 8-K filed April 19, 2002).
Exhibit 4	
*(a)	—Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated September 30, 2002 (filed as Exhibit 10.3 to Form 10-Q filed November 14, 2002).
*(b)	—Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated November 15, 2002 (filed as Exhibit 3.1 to Form 8-K filed November 19, 2002).
*(c)	—Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated November 15, 2002 (filed as Exhibit 3.2 to Form 8-K filed November 19, 2002).
*(d)	—Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Williams Energy Partners L.P. dated December 12, 2003 (filed as Exhibit 3(e) to Form 10-K filed March 8, 2004).

Exhibit No.	Description
Exhibit 10	
(a)	—Fourth Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated February 3, 2004.
(b)	—Magellan Pension Plan.
(c)	—Magellan 401(k) Plan.
(d)	—Description of Magellan Short-Term Incentive Program.
*(e)	—Contribution, Conveyance and Assumption Agreement dated February 9, 2001, between Williams Energy Partners L.P.; Williams OLP, L.P.; Williams GP LLC; Williams Energy Services, LLC; Williams Natural Gas Liquids, Inc.; Williams NGL, LLC; Williams Terminal Holdings, L.P.; Williams Terminal Holdings, L.L.C.; Williams Ammonia Pipeline, L.P. and Williams Bio-Energy, LLC (filed as Exhibit 10(b) to Form 10-K filed March 7, 2002).
*(f)	—Assignment, Assumption and Amendment Agreement dated November 15, 2002 among Williams GP LLC, WEG GP LLC, Williams Energy Partners L.P., Williams Energy Services, LLC and Williams Natural Gas Liquids, Inc. (filed as Exhibit 10 to Form 8-K filed November 19, 2002).
*(g)	—New Omnibus Agreement dated June 17, 2003 among WEG Acquisitions, L.P., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and The Williams Companies, Inc. (filed as Exhibit 10.3 to Form 8-K filed June 17, 2003).
*(h)	—ATLAS 2000 System Assignment, Contribution and License Agreement between Williams Energy Services, LLC and Williams Energy Partners L.P. (filed as Exhibit 10.4 to Form 8-K filed June 17, 2003).
*(i)	—Services Agreement dated June 17, 2003 among Williams Petroleum Services, LLC, Williams Alaska Pipeline Company, LLC and Williams Pipe Line Company, LLC (filed as Exhibit 10.5 to Form 8-K filed June 17, 2003).
*(j)	—Services Agreement dated June 17, 2003 among WEG GP LLC, Williams Energy Partners L.P. and WEG Acquisitions, L.P. (filed as Exhibit 10.6 to Form 8-K filed June 17, 2003).
*(k)	—Credit Agreement dated August 6, 2003 among Williams Energy Partners L.P., as borrower, the several lenders thereto, Lehman Brothers Inc., Banc of America Securities, LLC, as Joint Lead Arrangers, Bank of America, N.A., as Syndication Agent, and Lehman Commercial Paper Inc., as Administrative Agent (filed as Exhibit 10.2 to Form 10-Q filed November 10, 2003).
*(l)	—Guarantee and Collateral Agreement dated August 6, 2003 by Williams Energy Partners L.P. and certain of its subsidiaries in favor of Lehman Commercial Paper Inc., as Administrative Agent (filed as Exhibit 10.3 to Form 10-Q filed November 10, 2003).
*(m)	—Assignment and Assumption Agreement dated September 4, 2003 by Magellan Asset Services, L.P. in favor of Lehman Commercial Paper Inc., as Administrative Agent (filed as Exhibit 10.4 to Form 10-Q filed November 10, 2003).
*(n)	—Note Purchase Agreement dated October 1, 2002 (filed as Exhibit 10.6 to Form 10-Q filed November 14, 2002).
*(o)	—Amendment No. 1 dated May 30, 2003 to Note Purchase Agreement dated October 1, 2002 (filed as Exhibit 10.1 to Form 8-K filed June 17, 2003).
*(p)	—Security Agreement dated October 1, 2002 (filed as Exhibit 10.7 to Form 10-Q filed November 14, 2002).
*(q)	—Collateral Agency Agreement dated October 1, 2002 (filed as Exhibit 10.8 to Form 10-Q filed November 14, 2002).

Exhibit No.	Description
Exhibit 14	
(a)	—Code of Ethics dated September 1, 2003 by Don R. Wellendorf, principal executive officer.
(b)	—Code of Ethics dated September 1, 2003 by John D. Chandler, principal financial and accounting officer.
Exhibit 21	—Subsidiaries of Magellan GP, LLC and Magellan Midstream Partners, L.P.
Exhibit 23	—Consent of Independent Auditor.
Exhibit 24	—Power of Attorney together with certified resolution.
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 sheet at December 31, 2003 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.

(b) Reports on Form 8-K.

On October 15, 2003, we filed a report on Form 8-K under Item 7, which set forth our general partners' consolidated balance sheet as of July 31, 2003 and December 31, 2002 with accompanying notes.

On October 27, 2003, we furnished a report on Form 8-K under Items 9 and 12, which discussed our earnings press release for the third quarter of 2003.

On November 24, 2003, we filed a report on Form 8-K dated November 21, 2003 under Items 5 and 7, which announced the approval by our common unitholders at our Annual Meeting of Limited Partners of the conversion of our class B common units into common units.

On December 11, 2003, we filed a report on Form 8-K under Item 5, which reiterated our 2003 earnings guidance and provided earnings guidance for 2004.

On December 19, 2003, we filed a report on Form 8-K dated December 18, 2003 under Items 5 and 7, which discussed a primary and secondary offering of our common units and attached certain agreements material to the offering.

On December 23, 2003, we filed a report on Form 8-K/A dated December 19, 2003 under Item 5, which amended the Form 8-K filed December 19, 2003 in order to correct a typographical error in our press release provided as an exhibit thereto.

(d) At December 31, 2003, we had no partially owned entities.

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, General Counsel
Attorney-in-fact

Date: March 10, 2004

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.

Name	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 10, 2004
/s/ JOHN D. CHANDLER* **John D. Chandler**	Treasurer and Chief Financial Officer of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004
/s/ PATRICK C. EILERS* **Patrick C. Eilers**	Director of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004
/s/ JUSTIN S. HUSCHER* **Justin S. Huscher**	Director of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004
/s/ PIERRE F. LAPEYRE, JR.* **Pierre F. Lapeyre, Jr.**	Director of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004
/s/ DAVID M. LEUSCHEN* **David M. Leuschen**	Director of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004
/s/ JAMES R. MONTAGUE* **James R. Montague**	Director of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004

Name	Title	Date
/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 10, 2004
/s/ MARK G. PAPA* **Mark G. Papa**	Director of Magellan GP, LLC, general partner of Magellan Midstream Partners, L.P.	March 10, 2004
*By: /s/ LONNY E. TOWNSEND **Lonny E. Townsend, General Counsel** ***Attorney-in-fact***		March 10, 2004