# 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, 2004**

**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). ☒ Yes ☐ No

The aggregate market value of the registrant's voting and non-voting common units held by non-affiliates computed by reference to the price at which the common units were last sold as of June 30, 2004, was $1,072,882,421.

As of March 1, 2005, there were outstanding 30,340,464 common units and 2,839,848 subordinated units.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2005 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

**MAGELLAN MIDSTREAM PARTNERS, L.P.**

**FORM 10-K**

**PART I**

**ITEM 1.** ***Business***

**(a) General Development of Business**

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

On January 29, 2004, we acquired ownership in 14 petroleum products terminals located in the southeastern United States. We paid $24.8 million for these facilities, incurred $0.6 million of closing costs and assumed $3.8 million of environmental liabilities. We previously owned a 79% interest in eight of these terminals and purchased the remaining ownership interest from Murphy Oil USA, Inc. In addition, the acquisition included sole ownership of six terminals that were previously jointly owned by Murphy Oil USA, Inc. and Colonial Pipeline Company.

On March 2, 2004, we acquired a 50% ownership in Osage Pipeline Company, LLC ("Osage Pipeline") for $25.0 million from National Cooperative Refining 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 Osage Pipeline is owned by NCRA.

On October 1, 2004, we acquired more than 2,000 miles of petroleum products pipeline system assets from Shell Pipeline Company LP and Equilon Enterprises LLC, which had operated these assets under the name Shell Oil Products US ("Shell") for approximately $487.4 million. In addition, we paid approximately $30.0 million for inventory related to a third-party supply agreement for which we received $14.0 million of cash collateral, assumed approximately $29.6 million of existing liabilities and expect to incur approximately $9.6 million for transaction costs, of which $6.3 million had been incurred as of December 31, 2004. These assets are located in Colorado, Kansas, Oklahoma and Texas and primarily comprise four refined petroleum products pipeline systems with related terminalling and storage facilities that have a combined storage capacity of approximately 5.8 million barrels.

**(b) Financial Information About Segments**

See Part II, Item 8—Financial Statements and Supplementary Data

**(c) Narrative Description of Business**

We are principally engaged in the transportation, storage and distribution of refined petroleum products and ammonia. Our asset portfolio currently consists of:

- an 8,500-mile petroleum products pipeline system, including 43 petroleum products terminals, serving the mid-continent region of the United States;
- six petroleum products terminal facilities located along the Gulf Coast and near the New York harbor, which we refer to as our marine terminals;
- 29 petroleum products terminals located principally in the southeastern United States, which we refer to as our inland terminals; and
- an 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 markets by providing storage, distribution, blending and other ancillary services. Petroleum products transported, stored and distributed through our petroleum products pipeline system and petroleum products terminals include:

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

The Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. According to the Energy Information Administration's "Petroleum Supply Report for 2003", the Gulf Coast region accounted for approximately 43% of total U.S. daily refining capacity and 67% of U.S. refining capacity expansion from 1999 to 2003. The growth in Gulf Coast refining capacity has resulted in part from consolidation in the petroleum industry to take advantage of economies of scale from operating larger, concentrated refineries. We expect this trend to continue in order to meet growing domestic and international demand. According to the Energy Information Administration's "Petroleum Supply Report for 2003", the amount of petroleum products exported from the Gulf Coast region increased by approximately 28%, or 299 million barrels from 1990 to 2003. The growth in refining capacity and increased product flow attributable to the Gulf Coast region has increased demand for transportation, storage and distribution facilities.

## PETROLEUM PRODUCTS PIPELINE SYSTEM

During October 2004, we acquired a 2,000-mile petroleum products pipeline system from affiliates of Shell. This strategic acquisition extended the reach of our existing pipeline system into key markets in Colorado and western and northern Texas. This pipeline system was already interconnected with our existing petroleum products pipeline in Oklahoma, thereby providing us with a direct connection to the U.S. Gulf Coast, which is the primary refining region of the United States and a major point of entry for foreign imports of refined petroleum products. As a result, our common carrier petroleum products pipeline system now extends 8,500 miles and covers a 13-state area, extending from Texas through the Midwest to Colorado, North Dakota, Minnesota and Illinois. Our pipeline system transports petroleum products and LPGs and includes 43 terminals. The products transported on our pipeline system are largely transportation fuels, and in 2004 were comprised of 55% gasoline, 35% distillates (which includes diesel fuels and heating oil) and 10% LPGs and aviation fuel. Product originates on our pipeline system from direct connections to refineries and interconnections with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end-users. See Note 18—Segment Disclosures in the accompanying consolidated financial statements for financial information about the petroleum products pipeline system segment. The petroleum products pipeline system segment accounted for 83%, 80% and 79% of our consolidated total revenues in 2004, 2003 and 2002, respectively.

Our petroleum products pipeline system is dependent on the ability of refiners and marketers to meet the demand for refined petroleum products and LPGs in the markets it serves through their shipments on our pipeline system. According to statistics provided by the Energy Information Administration, the demand for refined petroleum products in the primary market areas served by our petroleum products pipeline system, known as Petroleum Administration for Defense District ("PADD") II, is expected to grow at an average rate of approximately 1.5% per year over the next 10 years. The total production of refined petroleum products from refineries located in PADD II is currently insufficient to meet the demand for refined petroleum products in PADD II. The excess PADD II demand has been and is expected to be met largely by imports of refined petroleum products via pipelines from Gulf Coast refineries that are located in PADD III, which represents the Gulf Coast region.

Our petroleum products pipeline system is well connected to Gulf Coast refineries. In addition to our own pipeline that originates in the Gulf Coast region, we also have interconnections with the Explorer, CITGO and Seaway/ConocoPhillips pipelines. These connections to Gulf Coast refineries, together with our pipeline's extensive network throughout PADD II and connections to PADD II refineries, should allow 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 7.2% from 2002 to 2004. The volume increases have come through a combination of acquisitions, 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:

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| Shipments (thousands of barrels): | | | |
| Refined products | | | |
| Gasoline | 139,073 | 137,752 | 139,566 |
| Distillates | 73,559 | 78,264 | 88,989 |
| Aviation fuel | 14,081 | 13,691 | 16,613 |
| LPGs | 7,910 | 7,922 | 8,385 |
| | 234,623 | 237,629 | 253,553 |
| Capacity lease | 25,465 | 25,647 | 25,324 |
| Total shipments | 260,088 | 263,276 | 278,877 |
| Daily average (thousands of barrels) | 713 | 721 | 762 |

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

***Operations***

Our petroleum products pipeline system is the largest common carrier pipeline for refined petroleum products and LPGs in the United States in terms of pipeline miles. Through direct refinery connections and interconnections with other interstate pipelines, our system can access approximately 43% of the refinery capacity in the continental United States. In general, we do not take title to the petroleum products we transport except with respect to a specific product supply agreement that we assumed in October 2004 and our petroleum products management operation.

Our petroleum products pipeline system generates approximately 80% of its revenue, excluding product sales revenues, through transportation tariffs on volumes shipped. These transportation tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All interstate transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission ("FERC"). Included as a part of these tariffs are charges for terminalling and storage of products at 38 of our pipeline system's 43 terminals. Revenues from terminalling and storage at five of our terminals are at privately negotiated rates. 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 54% of the shipments in 2004 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 20% of its revenues, excluding product sales revenues, from leasing pipeline and storage tank capacity to shippers and from providing product and other services such as ethanol unloading and loading, additive injection, laboratory testing and data services to shippers. Product services such as ethanol unloading and loading, additive injection, custom blending and laboratory testing are performed under a mix of "as needed", monthly and long-term agreements. We began operating the Rio Grande pipeline system in 2003. In January 2004 we began serving as a subcontractor to an affiliate of Williams for the operations of Longhorn Partners Pipeline, L.P. ("Longhorn") and during March 2004 we began operating the Osage Pipeline system. We receive fees for performing these services. Effective April 1, 2005, we have resigned as the operator of the Rio Grande pipeline system.

Product sales revenues primarily result from: (i) a third-party supply agreement assumed as part of the assets acquired from Shell; (ii) the sale of products that are produced from fractionating transmix; and (iii) our petroleum products management operation. We take title to the products related to these activities. Although the revenues generated from these activities were $267.7 million and $107.6 million in 2004 and 2003, respectively, the difference between product sales and product purchases was only $18.5 million and $9.7 million in 2004 and 2003, respectively, as product purchases were $249.2 million in 2004 and $97.9 million in 2003. Revenues increased in 2004 over 2003 by $160.1 million primarily as a result of our third-party supply agreement assumed with the assets acquired from Shell.

***Facilities***

Our petroleum products pipeline system consists of an 8,500-mile pipeline and includes 26.4 million barrels of aggregate usable storage capacity at terminals and various storage facilities along the system. The terminals deliver petroleum products primarily into tank trucks.

The following table contains information regarding our owned terminal facilities:

| Facilities | Total Usable Storage Capacity (barrels in millions) |
|---|---|
| Arkansas | |
| Ft. Smith | 0.2 |
| Colorado | |
| Aurora | 0.6 |
| Illinois | |
| Amboy | 0.2 |
| Chicago | 0.5 |
| Heyworth | 0.4 |
| Menard County | 0.2 |
| Iowa | |
| Des Moines | 2.1 |
| Dubuque | 0.1 |
| Ft. Dodge | 0.1 |
| Iowa City | 0.6 |
| Mason City | 0.6 |
| Milford | 0.2 |
| Sioux City | 0.6 |
| Waterloo | 0.4 |
| Kansas | |
| Great Bend | 0.1 |
| Kansas City | 1.6 |
| Olathe | 0.2 |
| Scott City | 0.3 |
| St. Joseph | 0.1 |
| Topeka | 0.1 |
| Minnesota | |
| Alexandria | 0.6 |
| Mankato | 0.4 |
| Marshall | 0.2 |
| Minnesota (cont.) | |
| Minneapolis | 1.8 |
| Rochester | 0.1 |
| Missouri | |
| Carthage | 0.1 |
| Columbia | 0.3 |
| Palmyra | 0.2 |
| Springfield | 0.3 |
| Nebraska | |
| Capehart | 0.1 |
| Doniphan | 0.5 |
| Lincoln | 0.1 |
| Omaha | 0.9 |
| North Dakota | |
| Fargo | 0.6 |
| Grand Forks | 0.3 |
| Oklahoma | |
| Enid | 0.3 |
| Oklahoma City | 0.3 |
| Tulsa | 2.6 |
| South Dakota | |
| Sioux Falls | 0.6 |
| Watertown | 0.2 |
| Texas | |
| Odessa | 0.7 |
| Wisconsin | |
| Wausau | 0.2 |
| In-transit storage | 5.8 |
| Total | 26.4 |

In addition, we have an agreement with ConocoPhillips which provides us the right to use their terminal facility at Wichita, Kansas. As part of the assets acquired from Shell, we purchased an additional terminal in Oklahoma City, Oklahoma which the Federal Trade Commission is requiring us to sell.

### *Petroleum Products Supply*

Petroleum products originate from both refining and pipeline interconnection points along our pipeline system. In 2004, 59% of the petroleum products transported on our petroleum products pipeline system originated from 10 direct refinery connections and 41% originated from 11 interconnections with other pipelines. As set forth in the table below, our system is directly connected to, and receives product from, 10 operating refineries.

**Major Origins—Refineries (Listed Alphabetically)**

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

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

**Major Origins—Pipeline Connections (Listed Alphabetically)**

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

### *Customers and Contracts*

We ship petroleum products for several different types of customers, including independent and integrated oil companies, wholesalers, retailers, railroads, airlines and regional farm cooperatives. End markets for these deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots and military and commercial jet fuel users. Propane shippers include wholesalers and retailers who, in turn, sell to commercial, industrial, agricultural and residential heating customers, as well as utilities who use propane as a fuel source.

For the year ended December 31, 2004, 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, 2004, represented 54% of total revenues for our petroleum products pipeline system and 63% of revenues excluding product sales.

Product sales primarily relate to the third-party supply agreement we assumed in connection with the assets acquired from Shell, sales of transmix and other petroleum products to trading and marketing companies.

See “Related Party Transactions” in Management’s Discussion and Analysis of Financial Condition and Results of Operations in this report for a discussion of our affiliate relationship with SemGroup, L.P. and its affiliates.

#### *Markets and Competition*

In certain markets, barge, truck or rail provide an alternative source for transporting refined products; however, pipelines are generally the lowest-cost alternative for petroleum product movements between different markets. As a result, our pipeline system’s most significant competitors are other pipelines that serve the same markets.

Competition with other pipeline systems is based primarily on transportation charges, quality of customer service, proximity to end-users and longstanding customer relationships. However, given the different supply sources on each pipeline, pricing at either the origin or terminal point on a pipeline may outweigh transportation costs when customers choose which line to use.

Another form of competition for all pipelines is the use of exchange agreements among shippers. Under these arrangements, a shipper will agree to supply a market near its refinery or terminal in exchange for receiving supply from another refinery or terminal in a more distant market. These agreements allow the two parties to reduce the volumes transported and the average transportation rate paid to us. We have been able to compete with these alternatives through price incentives and through long-term commercial arrangements with potential exchange partners. Nevertheless, a significant amount of exchange activity has occurred historically and is likely to continue.

## PETROLEUM PRODUCTS TERMINALS

Within our petroleum products terminals network, we operate two types of terminals: marine terminals and inland terminals. Our marine terminals are located in close proximity to refineries and are large storage and distribution facilities that handle refined petroleum products, blendstocks, ethanol, heavy oils, feedstocks, crude oil and condensate. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as 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. See Note 18—Segment Disclosures in the accompanying consolidated financial statements for financial information about the petroleum products terminals segment. The petroleum products terminals segment accounted for 15%, 17% and 18% of our consolidated total revenues in 2004, 2003 and 2002, respectively.

### Marine Terminals

We own and operate six marine terminals, including five marine terminals located along the Gulf Coast and one terminal located in Connecticut near the New York harbor. We acquired one of these terminals in October 2004 as a part of the assets acquired from Shell. Our marine terminals are large storage and distribution facilities, with an aggregate storage capacity of approximately 18.8 million barrels, that provide inventory management, storage and distribution services for refiners and other large end-users of petroleum products.

Our marine terminals primarily receive petroleum products by ship and barge, short-haul pipeline connections from neighboring refineries and common carrier pipelines. We distribute petroleum products from our marine terminals by all of those means as well as by truck and rail. Once the product has reached our marine terminals, we store the product for a period of time ranging from a few days to several months. Products that we store include petroleum products, blendstocks, crude oils, heavy oils and feedstocks. In addition to providing storage and distribution services, our marine terminals provide ancillary services including heating, blending and mixing of stored products and additive injection services.

Our marine terminals generate fees primarily through providing long-term or spot demand storage services and inventory management for a variety of customers. In general, we do not take title to the products that are stored in or distributed from our terminals. Refiners and chemical companies will typically use our marine terminals because their facilities are inadequate, either because of size constraints or the specialized handling requirements of the stored product. We also provide storage services and inventory management to various industrial end-users, marketers and traders that require access to large storage capacity.

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

| Facility | Usable Storage Capacity (Million Barrels) | Primary Products Handled | Connections |
|---|---|---|---|
| Connecticut | | | |
| New Haven | 3.8 | Refined petroleum products, ethanol, feedstocks and asphalt | Pipeline, barge, ship and truck |
| Louisiana | | | |
| Gibson | 0.1 | Crude oil and condensate | Pipeline, barge and truck |
| Marrero | 1.6 | Heavy oils and feedstocks | Barge, ship, rail and truck |
| Texas | | | |
| Corpus Christi | 2.6 | Blendstocks, heavy oils and feedstocks | Pipeline, barge, ship and truck |
| East Houston | 1.9 | Refined petroleum products, blendstocks and crude oil | Pipeline, barge, ship, rail and truck |
| Galena Park | 8.8 | Refined petroleum products, blendstocks, heavy oils and feedstocks | Pipeline, barge, ship, rail and truck |
| Total storage capacity | 18.8 | | |

***Customers and Contracts***

We have long-standing relationships with oil refiners, suppliers and traders at our facilities. During 2004, approximately 98% of our marine terminal capacity was utilized. As of December 31, 2004, approximately 60% of our usable storage capacity is under long-term contracts with remaining terms in excess of one year or that renew on an annual basis.

***Markets and Competition***

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

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

**Inland Terminals**

We own and operate a network of 29 refined petroleum products terminals located primarily in the southeastern United States. We acquired six of these terminals in January 2004 and also acquired the remaining 21% ownership interest in eight terminals in which we previously had a 79% ownership interest. As a result, we now wholly own 26 of the 29 terminals in our portfolio. Our terminals have a combined capacity of 5.5 million barrels. Our customers utilize these facilities to take delivery of refined petroleum products transported on major common carrier interstate pipelines. The majority of our inland terminals connect to the Colonial, Explorer, Plantation or TEPPCO pipelines and some facilities have multiple pipeline connections. During 2004, gasoline represented approximately 60% of the product volume distributed through our inland terminals, with the remaining 40% consisting of distillates.

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

We are an independent provider of storage and distribution services. Because we generally do not own the products moving through our terminals, we are not exposed to the risks of product ownership. We operate our inland terminals as distribution terminals and we primarily serve the retail, industrial and commercial sales markets. We provide inventory and supply management, distribution and other services such as injection of gasoline additives at our inland terminals.

We generate revenues by charging our customers a fee based on the amount of product that we deliver through our inland terminals. We charge these fees when we deliver the product to our customers and load it into a truck or rail car. In addition to throughput fees, we generate revenues by charging our customers a fee for injecting additives into gasoline, diesel and aviation fuel, and for filtering jet fuel.

The following table sets forth our inland terminal locations, percentage ownership and usable storage capacities:

| Facility | Percentage Ownership | Total Usable Capacity (Million Barrels) | Pipeline Connections |
|---|---|---|---|
| Alabama | | | |
| Birmingham | 100 | 0.2 | Colonial and Plantation |
| Montgomery | 100 | 0.1 | Plantation |
| Arkansas | | | |
| Little Rock (2) | 100 | 0.4 | TEPPCO |
| Georgia | | | |
| Albany | 100 | 0.1 | Colonial |
| Doraville (2) | 100 | 0.6 | Colonial and Plantation |
| Macon | 100 | 0.1 | Colonial and Plantation |
| Missouri | | | |
| St. Charles | 100 | 0.2 | Explorer and ConocoPhillips |
| North Carolina | | | |
| Charlotte (2) | 100 | 0.4 | Colonial |
| Greensboro | 60 | 0.2 | Colonial |
| Greensboro | 100 | 0.2 | Colonial and Plantation |
| Selma | 100 | 0.3 | Colonial |
| South Carolina | | | |
| North Augusta (2) | 100 | 0.3 | Colonial |
| Spartanburg (2) | 100 | 0.3 | Colonial |
| Tennessee | | | |
| Chattanooga (2) | 100 | 0.3 | Colonial and Plantation |
| Knoxville (2) | 100 | 0.3 | Colonial and Plantation |
| Nashville | 50 | 0.2 | Colonial |
| Nashville (2) | 100 | 0.3 | Colonial |
| Texas | | | |
| Dallas | 100 | 0.4 | Explorer, Magtex, Magellan and Dallas Love Field |
| Southlake | 50 | 0.2 | Explorer, Koch and Valero |
| Virginia | | | |
| Montvale | 100 | 0.2 | Colonial |
| Richmond | 100 | 0.2 | Colonial |
| Total | | 5.5 | |

***Customers and Contracts***

When we acquire terminals, we generally enter into long-term throughput contracts with the sellers under which they agree to continue to use the facilities. In addition to these agreements, we enter into contracts with new customers that typically last for one year with a continuing one-year renewal provision. Most of these contracts contain a minimum throughput provision that obligates the customer to move a minimum amount of product through our terminals or pay for terminal capacity reserved but not used. Our customers include retailers, wholesalers, exchange transaction customers and traders.

***Markets and Competition***

We compete with other independent terminal operators as well as integrated oil companies on the basis of terminal location and versatility, services provided and price. Our competition primarily comes from distribution companies with marketing and trading arms, independent terminal operators and refining and marketing companies.

## AMMONIA PIPELINE SYSTEM

We own an 1,100-mile common carrier ammonia pipeline system. Our pipeline system transports ammonia from production facilities in Texas and Oklahoma to terminals in the Midwest. The ammonia we transport is primarily used as a nitrogen fertilizer, an important element for maintenance of high crop yields. Ammonia is the 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. See Note 18—Segment Disclosures in the accompanying consolidated financial statements for financial information about the ammonia pipeline system segment. The ammonia pipeline system segment accounted for 2% of our consolidated total revenues in 2004 and 3% in 2003 and 2002.

### *Operations*

We generate more than 90% 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. We do not produce or trade ammonia, and we do not take title to the ammonia we transport.

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

### *Facilities*

Our ammonia pipeline is one of two ammonia pipelines operating in the United States and has a maximum annual delivery capacity of approximately 900,000 tons. Our ammonia pipeline system originates at production facilities in Borger, Texas, Verdigris, Oklahoma and Enid, Oklahoma and terminates in Mankato, Minnesota.

We transport ammonia to 13 delivery points along our ammonia pipeline system, including 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.

### *Customers and Contracts*

We ship ammonia for three customers. Each of these customers has an ammonia production facility as well as related storage and distribution facilities connected to our ammonia pipeline. Our customers are currently 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. The transportation contracts with our customers extend through June 2005. We are currently negotiating the terms of new transportation contracts to be effective in July 2005.

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. Each of our customers nominates a tonnage that it expects to ship during the contract year. Our customers' aggregate annual commitments for the period July 1, 2004 through June 30, 2005 are 650,000 tons. If a customer fails to ship its annual commitment, that customer must pay for the pipeline capacity it did not use. 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 275,000 tons in this combined bank that may be used to offset future ship or pay obligations.

***Markets and Competition***

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

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

**Major Customers**

The percentage of revenues derived by customers that accounted for 10% or more of our consolidated total revenues is provided in the table below. Customer A is a customer of both our petroleum products pipeline system and petroleum products terminals segments. Customer B is a customer of our petroleum products pipeline system segment.

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| Customer A | 4% | 27% | 19% |
| Customer B | 0% | 0% | 13% |
| Total | 4% | 27% | 32% |

**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 for finished goods ("PPI-FG") less 1%. As required by its own regulations, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing rate indexing methodology. In December 2000, the FERC issued an order concluding that the rate index reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the U.S. Court of Appeals for the Washington D.C. Circuit, the FERC changed the rate indexing methodology to the PPI-FG, but without the subtraction of 1% as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2001. 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-FG. Approximately one-third of our petroleum products pipeline system is subject to this indexing methodology. In addition to rate indexing and cost-of-service filings, interstate oil pipeline companies may elect to support rate filings by obtaining authority to charge market-based rates or through an agreement between a shipper and the 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 filed appeals of the FERC's orders with the United States Court of Appeals. On July 20, 2004, the United States Court of Appeals for the District of Columbia issued its opinion relative to these appeals in BP West Coast Products, LLC v. FERC, which vacated the FERC's application of its Lakehead policy, with the result that no income tax allowance can be claimed by pipeline owners that are limited partnerships. Because the Court's ruling appears to focus on the facts and record presented to it in that specific case, it is not clear what impact, if any, the opinion will have on our indexed rates. On December 2, 2004, the FERC issued a Notice of Inquiry that seeks comments regarding whether BP West Coast applies only to the specific facts of that case, or whether it applies more broadly, and, if the latter, what effect that ruling might have on energy infrastructure investments. It is not clear what action the FERC will ultimately take in response to the Court's ruling and the comments received regarding the Notice of Inquiry, and to what extent such action will be challenged and, if so, whether such action will withstand further judicial review. Nevertheless, a shipper might rely on this decision to challenge our indexed rates based on a changed circumstance argument. If the FERC disallowed our income tax allowance, it may be more difficult to justify our rates on a cost of service basis. However, because of the relatively small percentage of our unitholders that are corporations, we include only a small income tax allowance in our cost of service based on the current Lakehead policy, and so we do not believe that a challenge to our indexed rates based solely on the changed circumstance of the elimination of our income tax allowance would likely succeed.

The Surface Transportation Board ("STB"), a part of the United States Department of Transportation, has jurisdiction over interstate pipeline transportation and rate regulations of ammonia. Transportation rates must be reasonable and a pipeline carrier may not unreasonably discriminate among its shippers. If the STB finds that a carrier's rates violate these statutory commands, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives.

The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

*Intrastate Regulation*

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

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

### Maintenance and Safety Regulations

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

Our assets are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request. At qualifying facilities, we are subject to OSHA Process Safety Management regulations that are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals.

Our pipeline systems are also subject to regulation by the United States Department of Transportation under the Hazardous Liquid Pipeline Safety Act (“HLPSA”) of 1979, as amended, and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. HLPSA covers petroleum, petroleum products and anhydrous ammonia and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to make certain reports and provide information as required by the Department of Transportation.

In December 2000, the Department of Transportation adopted new regulations requiring operators of hazardous liquid interstate pipelines to develop and follow an integrity management program that provides for assessment of the integrity of all pipeline segments that could affect designated “high consequence areas,” including high population areas, drinking water, commercially navigable waterways and ecologically sensitive resource areas. Segments of our pipeline systems have the potential to impact high consequence areas. We have spent approximately $32.0 million relative to integrity assessments and anticipate spending approximately $45.0 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.

In 2003, Shell entered into a consent decree with the EPA which, among other things, included testing, maintenance, monitoring and reporting requirements for two of the pipelines we acquired from Shell. The consent decree extends until 2008. Under our purchase agreement with Shell, we agreed, at our own expense, to complete any remaining corrective action(s) required under the consent decree with respect to these pipelines and accordingly recognized a liability of approximately $8.6 million. Shell retains responsibility to the EPA for compliance with the terms of the consent decree.

Our marine terminals are subject to United States Coast Guard regulations and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of these assets.

### Environmental

*General*

The operation of our pipeline systems, terminals and associated facilities is subject to strict and complex laws and regulations relating to the protection of the environment. This body of laws and regulations regulates many aspects of our business including the generation and disposal of waste, discharge of process and storm water, air emissions, remediation requirements as well as facility design requirements to protect against releases into the environment. As an owner or lessee and operator of these facilities, we comply with federal, state and local laws and regulations.

Estimates provided below for remediation costs assume that we will be able to use traditionally acceptable remedial and monitoring methods, as well as associated engineering or institutional controls to comply with applicable regulatory requirements. These estimates include the cost of performing environmental assessments, remediation and monitoring of the impacted environment such as soils, groundwater and surface water conditions. Remediation costs are estimates only and we cannot predetermine whether the actual total remediation costs will exceed estimated amounts. We are not aware of any potential claims by third parties that could be materially adverse to our operations, financial position or cash flow.

We may experience future releases of regulated materials into the environment or discover historical releases that were previously unidentified or not assessed. While an asset integrity and maintenance program designed to prevent and promptly detect and address releases is an integral part of our operations, damages and liabilities arising out of any future environmental release from our assets have the potential to have a material adverse effect on our financial position, cash flow and results of operations.

*Former Williams Indemnities*—Prior to May 27, 2004, we had three separate indemnification agreements with Williams and its affiliates. These three agreements are described below:

*IPO Indemnity Agreement*—Williams and certain of its affiliates indemnified us for covered environmental losses up to $15.0 million related to assets operated by us at the time of our initial public offering date (February 9, 2001) that became known by August 9, 2004 and that exceed amounts recovered or recoverable under our contractual indemnities from third persons or under any applicable insurance policies. We refer to this indemnity as the "IPO Indemnity". Covered environmental losses included those non-contingent terminal and ammonia system environmental losses, costs, damages and expenses suffered or incurred by us 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. In addition, Williams and certain of its affiliates indemnified us 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 also indemnified us 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.

*Magellan Pipeline Indemnity Agreement*—In conjunction with the acquisition of Magellan Pipeline Company, L.P. ("Magellan Pipeline") in April 2002, Williams agreed to indemnify us for any breaches of representations or warranties, environmental liabilities and failures to comply with environmental laws as described below. Williams' liability under this indemnity was capped at $125.0 million. We refer to this indemnity as the "Magellan Pipeline Indemnity". In addition to environmental liabilities, this indemnity included matters relating to employees and employee benefits and real property, including asset titles. Also, this indemnity provided that we were indemnified for an unlimited amount of losses and damages related to tax liabilities. The environmental liability indemnity included any losses and damages related to environmental liabilities caused by events that occurred prior to the acquisition. Covered environmental losses included those losses arising from the correction of violations of, or performance of remediation required by, environmental laws in effect at April 11, 2002.

*Acquisition Indemnity Agreement*—In addition to these two agreements, the purchase and sale agreement entered into in connection with MMH's acquisition of Williams' partnership interest in us provided us with two additional indemnities related to environmental liabilities, which we collectively refer to as the "Acquisition Indemnity".

First, MMH assumed Williams' obligations to indemnify us for $21.9 million of known environmental liabilities.

Second, 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 the IPO Indemnity and Magellan Pipeline Indemnity agreements described above. This additional indemnification included those liabilities related to the 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 covered environmental as well as other liabilities.

*Indemnification Settlement*—In May 2004, we and our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from the environmental indemnifications and certain other indemnifications provided under the IPO Indemnity, Magellan Pipeline Indemnity and Acquisition Indemnity agreements described above. We received $35.0 million from Williams on July 1, 2004 and expect to receive installment payments from Williams of $27.5 million, $20.0 million and $35.0 million on July 1, 2005, 2006 and 2007, respectively.

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

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

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

- In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to Williams based on a preliminary determination that Williams may have systematic problems with petroleum discharges from Magellan Pipeline operations. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those spills may have also violated the Spill Prevention, Control and Countermeasure ("SPCC") requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these spills if the EPA were to successfully seek and obtain injunctive relief. We have submitted all information requested to date. We have met with the EPA and the DOJ and anticipate negotiating a final settlement with both agencies in 2005. We have accrued an amount that is less than $22.0 million associated with this matter;
- Estimated environmental liabilities assumed in conjunction with acquisitions completed during 2004, which totaled $6.1 million; and
- Estimated environmental liabilities recorded as a part of our on-going operations.

*Other Environmental Matters*—We have notified the Texas Commission on Environmental Quality regarding certain potential air permit non-compliance issues associated with the Galena Park terminal. At this time, we cannot assess the materiality of these notifications. In addition, we have entered into a consent agreement with the Oklahoma Department of Environmental Quality that resolves a prior air emission concern at Magellan Pipeline's Enid terminal. Under the agreement we have agreed to invest approximately $2.0 million in capital costs and pay a civil penalty of $475,000.

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

We are currently assessing the applicability of the EPA's Prevention of Significant Deterioration regulations to certain of our facilities based on recent EPA guidance. Depending on the outcome of this assessment, we may be required to upgrade air pollution control equipment at certain of these facilities. At this time, we are unable to determine what the outcome of this might be and the impact it will have, if any, on our results of operations, financial position and cash flows.

*Environmental Receivables*—In June 2003, MMH assumed a $21.9 million obligation from Williams to indemnify us for certain identified environmental liabilities (previously identified under *Acquisition Indemnity Agreement* above. As of December 31, 2004, we had received $10.4 million from MMH associated with this indemnification, resulting in a remaining associated receivable from MMH of $11.5 million. Environmental receivables from insurance carriers were $7.4 million at December 31, 2004.

*Insurance Policies*—We have insurance policies which provide coverage for environmental matters associated with liabilities arising from sudden and accidental releases of products applicable to all of our assets. In conjunction with acquisitions, we generally purchase pollution legal liability insurance to cover pre-existing unknown conditions for the acquired assets with deductibles ranging from $0.1 million to $0.3 million.

*Environmental Indemnifications From Third Parties*—Described below are environmental indemnifications provided by outside entities when we acquired certain of our assets:

- In connection with the assets acquired from Shell in October 2004, Shell retained liability for ongoing remediation for certain active remediation sites until monitoring only, or site closure, is received from the appropriate regulatory agencies. In addition, Shell agreed to indemnify us for certain environmental liabilities arising from pre-closing conditions identified by October 1, 2006. Shell's environmental indemnification obligation is subject to a $0.3 million per-claim deductible and a $30.0 million aggregate cap;
- We acquired 100% ownership in six petroleum products terminals in the Southeast through a series of four transactions: (1) a 45.5% interest in the terminals was acquired from Conoco, Inc. in 1996; (2) a 23.5% interest was acquired from TOC Terminals, 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 $0.5 million. Under the 2004 agreement, we assumed liability for 31.0% of known environmental liabilities. We have also assumed liability for all unknown 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;
- 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 known PCB contamination. We assumed all other environmental liabilities;
- In connection with the 1999 acquisition of our Gulf Coast marine terminals, Amerada Hess Corporation ("Hess") retained certain liabilities, including liabilities for the performance of corrective actions associated with hydrocarbon recovery from ground water at our Corpus Christi terminal. However, if closure related to these corrective actions has not been received by July 2014, 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; however, if closure has not been received by January 7, 2014, we will assume any remaining liability; and
- In connection with the acquisition of the Dallas terminal in December 1997, Mobil Oil Corporation retained liability for ongoing remediation activities; however, if closure has not been received by December 29, 2013, we will assume any remaining liability.

*Outstanding Indemnity Claim*—We have filed claims totaling $1.9 million with Hess associated with their indemnifications to us in regards to our 1999 purchase of the Gulf Coast marine terminals. Our claims stated that remediation expenditures beyond our initial $1.9 million claim may be necessary and that our claims would be increased for any expenditures required beyond this amount. We are currently negotiating a settlement of our claims with Hess.

*Hazardous Substances and Wastes*

In most instances, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into water or soils, and include measures to control pollution of the environment. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment.

In 2003, 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. We have responded to a request from the EPA received in December 2004 seeking additional data regarding one site. We responded that we have found no information regarding the site. The EPA has not responded to the other matter.

Our operations also generate wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations routinely generate only small quantities of hazardous wastes, and we do not hold ourselves out as a hazardous waste treatment, storage or disposal facility operator that is required to obtain a RCRA hazardous waste permit. While RCRA currently exempts a number of wastes, including many oil and gas exploration and production wastes, from being subject to hazardous waste requirements, the EPA can consider the adoption of stricter disposal standards for non-hazardous wastes. Moreover, it is possible that additional wastes, which could include non-hazardous wastes currently generated during operations, may be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly storage and disposal requirements than are non-hazardous wastes. Changes in the regulations could have a material adverse effect on our expenses.

We own or lease properties where hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on, under or from the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to the Superfund law, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by prior owners or operators, to remediate contaminated property, including groundwater contaminated by prior owners or operators, or to make capital improvements to prevent future contamination. Although potential costs associated with the removal or remediation of previously disposed wastes is unknown, we do not expect these potential costs to have a material adverse effect on our financial condition or results of operations.

*Above Ground Storage Tanks*

States in which we operate typically have laws and regulations governing above ground tanks containing liquid substances. Generally, these laws and regulations require that these tanks include secondary containment systems or that the operators take alternative precautions to ensure that no contamination results from any leaks or spills from the tanks. The Department of Transportation Office of Pipeline Safety has incorporated American Petroleum Institute Standard No. 653 to regulate above ground tanks subject to their jurisdiction. As part of our assessment of facility operations we have identified some above ground tanks at our terminals that either are, or are suspected of being, coated with lead-based paints. The removal and disposal of any paints that are found to be lead-based, whenever such activities are conducted in the future as part of our day-to-day maintenance activities, will require increased handling by us. However, we do not expect the costs associated with this increased handling to be significant. We believe that the future implementation of above ground storage tank laws or regulations will not have a material adverse effect on our 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 significant liability for removal costs and certain other consequences of an oil spill such as natural resource damages, where the spill is into navigable waters, along shorelines or in the exclusive economic zone of the United States. In the event of an oil spill from one of our facilities into navigable waters, substantial liabilities could be imposed upon us. States in which we operate have also enacted similar laws. Regulations have been or are being developed under the Oil Pollution Act, as well as comparable state laws that may also impose additional regulatory burdens on our operations. Although the costs associated with complying with the amended regulations cannot be determined at this time, we do not expect these expenditures to have a material adverse effect on our 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. While we have exceeded permit discharges at some of our terminals, we do not expect our non-compliance with existing permits and foreseeable new permit requirements to have a material adverse effect on our 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. 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.

### 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 in February 2001 and (2) title defects related to the portion of our petroleum products pipeline system acquired from Williams in April 2002 that arise within ten years from the 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.

### Employees

To conduct our operations, MMH employs approximately 955 employees, of whom 506 conduct the operations of our petroleum products pipeline system, 209 conduct the operations of our petroleum products terminals and 240 provide general and administrative services.

## (d) Financial Information About Geographical Areas

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

## (e) Available Information

We file annual, quarterly and current reports, proxy statements and other information electronically with the Securities and Exchange Commission ("SEC"). You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 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 (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 ("NYSE"), 20 Broad Street, New York, New York 10005 or at the NYSE's Internet site (www.nyse.com). The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The chief executive officer of our general partner submitted an unqualified annual written certification to the NYSE during 2004 as required.

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.

### ITEM 2. *Properties*

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

### ITEM 3. *Legal Proceedings*

During 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act"), preliminarily determined that Williams may have systematic problems with petroleum discharges from pipeline operations. That inquiry primarily focused on Magellan Pipeline. The response to the EPA's information request was submitted during November 2001. In March 2004, we received the EPA's reply, which indicated that the EPA intends to fine us for as much as $22.0 million for violations under Section 311(b) of the Act associated with spills identified in the EPA's reply that occurred from March 1999 through January 2004. The EPA further indicated that some of those spills may have also violated the SPCC requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these spills if the EPA were to successfully seek and obtain injunctive relief. We have verbally agreed to a response schedule for the releases that occurred from March 1999 through January 2004 and have submitted a response in accordance to that schedule. We have met with the EPA and the DOJ and anticipate negotiating a final settlement with the EPA and the DOJ by the end of 2005. We have evaluated this issue and have accrued a liability based on our best estimates that is less than $22.0 million.

On March 22, 2004, we received a Corrective Action Order from the Department of Transportation Southwest Region Office of Pipeline Safety ("OPS") as a result of the OPS' May 2003 inspection of a former affiliates' Integrity Management Program applicable to our assets. The Corrective Action Order focused on timing of repairs and temporary pressure reductions upon discovery of anomalies. The OPS preliminarily assessed us with a civil penalty of $105,000. Supplemental information was presented to the OPS in September 2004. We are awaiting the OPS' response on this matter.

The Oklahoma Department of Environmental Quality ("ODEQ") has alleged in a Notice of Violation dated June 14, 2002 that a terminal on our petroleum products pipeline system located in Enid, Oklahoma was subject to the Maximum Achievable Control Technology ("MACT") standards at 40 C.F.R 63.420-429, National Emission Standard for Gasoline Distribution Facilities. During July 2004, we reached a verbal agreement with ODEQ to comply with the MACT requirements and to pay a penalty of $475,000.

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

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

None

## PART II

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

We completed our initial public offering in February 2001, and our common units began trading on the New York Stock Exchange under the ticker symbol "WEG". Since our name change to Magellan Midstream Partners, L.P. on September 1, 2003, our common units have been listed on the New York Stock Exchange under the ticker symbol "MMP". At the close of business on March 1, 2005, we had 184 registered holders and approximately 37,500 beneficial holders of record of our common units. The high and low closing sales price ranges and distributions paid by quarter for 2003 and 2004 are as follows:

| | 2003 | | | 2004 | | |
|---|---|---|---|---|---|---|
| Quarter | High | Low | Distribution* | High | Low | Distribution* |
| 1st | $37.19 | $33.30 | $0.7500 | $55.35 | $50.05 | $0.8500 |
| 2nd | $48.20 | $37.54 | $0.7800 | $55.50 | $46.89 | $0.8700 |
| 3rd | $48.55 | $42.40 | $0.8100 | $55.00 | $49.77 | $0.8900 |
| 4th | $55.03 | $45.80 | $0.8300 | $59.34 | $53.01 | $0.9125 |

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

In addition to common units, we also issued 5,679,694 subordinated units as part of our initial public offering in February 2001. In accordance with the early conversion criteria described below, 2,839,846 of these units have converted to common units, leaving 2,839,848 subordinated units outstanding as of March 1, 2005. There is no established public trading market for these units. All of the subordinated units are held by MMH, and MMH receives a quarterly distribution on these units only after sufficient funds have been paid to the common units, as also described below. In addition, the subordinated units generally have reduced voting rights equal to one-half vote for each unit owned.

During the subordination period, the holders of our common units are entitled to receive 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 were eligible to convert to common units on a one-for-one basis after December 31, 2003 and one-quarter of the subordinated units were eligible to convert to common units on a one-for-one basis after December 31, 2004 if we met 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. We also met the second early conversion test effective February 2005, with another 1,419,923 subordinated units converted to common units at that time. Following this second early conversion, we have 2,839,848 subordinated units outstanding. Because of these conversions, the common units have less protection with respect to distributions and the subordinated units that converted into common units have 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 $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 conjunction with our acquisition of petroleum products pipeline assets during October 2004, our general partner agreed to reduce the amount of its incentive distributions by $1.25 million per quarter for distributions associated with fourth-quarter 2004 and all quarters of 2005 and by $0.75 million for all quarters of 2006.

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 $0.9125 per limited partner unit, which, including the impact of the reductions in our general partners' incentive distributions as discussed above, entitles our general partner to receive approximately 15% 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.

**Equity Compensation Plans**

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

**ITEM 6.**

## SELECTED FINANCIAL AND OPERATING DATA

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

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, 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 Williams and us, operating results from Magellan Pipeline's petroleum products management operation, other than an annual fee of approximately $4.0 million, were not included in our financial results subsequent to April 2002. In addition, general and administrative expenses related to the petroleum products pipeline system for which we had been reimbursing our general partner, were subject to a cap under our operating agreement (see *Reimbursement of G&A Expense* under Note 12—Related Party Transactions in the accompanying consolidated financial statements). The ATLAS 2000 software system assets were contributed to us on June 17, 2003 in conjunction with the sale by Williams of its interests in us (see *Change in Ownership of General Partner* under Note 1—Organization and Basis of Presentation in the accompanying consolidated financial statements), and the depreciation expense associated with those assets has been included in our results since that date. Also, we acquired Williams' interest in the petroleum products management operation in July 2003 (see Note 6—Acquisitions in the accompanying consolidated financial statements), and the results of this operation have been included in our results subsequent to that date.

In October 2004, we acquired certain assets from Shell for a total purchase price of $553.3 million (see Note 6—Acquisitions in the accompanying consolidated financial statements), which had a significant impact on our operating results, financial position and cash flows during the fourth quarter of 2004.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial conditions or results of operations. A discussion of our critical accounting estimates is included in *Management's Discussion and Analysis of Financial Condition and Results of Operations* under Item 7 of this report. In addition, a discussion of our environmental liabilities and indemnifications can be found in Item 1. Business—Environmental, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 19—Commitments and Contingencies in the accompanying consolidated financial statements.

We define EBITDA, a non-generally accepted accounting principles measure presented in the following schedules as net income plus provision for income taxes, debt prepayment premiums, write-off of unamortized debt placement fees, debt placement fee amortization, interest expense (net of interest income) and depreciation and amortization. EBITDA should not be considered an alternative to net income, operating profit, cash flow from operations or any other measure of financial performance presented in accordance with 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. We compute the components of operating margin by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables (see Note 18—Segment Disclosures in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit). We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items such as depreciation and amortization and general and administrative costs, that management does not consider when evaluating the core profitability of an operation.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 | 2001 | 2002 | 2003 | 2004 |
| | (in thousands, except per unit amounts) | | | | |
| **Income Statement Data:** | | | | | |
| Transportation and terminals revenues | $ 318,121 | $ 339,412 | $ 363,740 | $ 372,848 | $ 416,408 |
| Product sales revenues | 106,873 | 108,169 | 70,527 | 112,312 | 278,478 |
| Affiliate construction and management fee revenues | 1,852 | 1,018 | 210 | — | 488 |
| Total revenues | 426,846 | 448,599 | 434,477 | 485,160 | 695,374 |
| Operating expenses including environmental expenses net of indemnifications | 144,899 | 160,880 | 155,146 | 166,883 | 179,532 |
| Product purchases | 94,141 | 95,268 | 63,982 | 99,907 | 255,724 |
| Equity earnings | — | — | — | — | (1,602) |
| Affiliate construction expenses | 1,025 | — | — | — | — |
| Operating margin | 186,781 | 192,451 | 215,349 | 218,370 | 261,720 |
| Depreciation and amortization expense | 31,746 | 35,767 | 35,096 | 36,081 | 41,845 |
| Affiliate general and administrative expense | 51,206 | 47,365 | 43,182 | 56,846 | 54,466 |
| Operating profit | 103,829 | 109,319 | 137,071 | 125,443 | 165,409 |
| Interest expense, net | 25,329 | 12,113 | 21,758 | 34,536 | 35,435 |
| Debt prepayment premium | — | — | — | — | 12,666 |
| Write-off of unamortized debt placement costs | — | — | — | — | 5,002 |
| Debt placement fee amortization | — | 253 | 9,950 | 2,830 | 3,056 |
| Other (income) expense, net | (816) | (431) | (2,112) | (92) | (953) |
| Income before income taxes | 79,316 | 97,384 | 107,475 | 88,169 | 110,203 |
| Provision for income taxes[(a)] | 30,414 | 29,512 | 8,322 | — | — |
| Net income | $ 48,902 | $ 67,872 | $ 99,153 | $ 88,169 | $ 110,203 |
| Basic net income per limited partner unit | | $ 1.87 | $ 3.68 | $ 3.32 | $ 3.45 |
| Diluted net income per limited partner unit | | $ 1.87 | $ 3.67 | $ 3.31 | $ 3.44 |
| **Balance Sheet Data:** | | | | | |
| Working capital (deficit) | $ 17,828 | $ (2,211) | $ 47,328 | $ 77,438 | $ 71,737 |
| Total assets | 1,050,159 | 1,104,559 | 1,120,359 | 1,194,624 | 1,817,832 |
| Long-term debt | — | 139,500 | 570,000 | 569,100 | 789,568 |
| Affiliate long-term note payable[(b)] | 432,957 | 138,172 | — | — | — |
| Partners' capital | 388,503 | 589,682 | 451,757 | 498,149 | 789,109 |
| **Cash Flow Data:** | | | | | |
| Cash distributions declared per unit[(c)] | | $ 2.02 | $ 2.71 | $ 3.17 | $ 3.52 |
| Cash distributions paid per unit[(c)] | | $ 1.43 | $ 2.58 | $ 3.07 | $ 3.44 |

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 | 2001 | 2002 | 2003 | 2004 |
| | (in thousands, except per unit amounts) | | | | |
| **Other Data:** | | | | | |
| Operating margin: | | | | | |
| Petroleum products pipeline system | $147,778 | $143,711 | $163,233 | $162,494 | $192,841 |
| Petroleum products terminals | 31,286 | 38,240 | 43,844 | 46,909 | 58,522 |
| Ammonia pipeline system | 7,717 | 10,500 | 8,272 | 8,094 | 7,328 |
| Allocated partnership depreciation costs[d] | — | — | — | 873 | 3,029 |
| Operating margin | $186,781 | $192,451 | $215,349 | $218,370 | $261,720 |
| EBITDA: | | | | | |
| Net income | $ 48,902 | $ 67,872 | $ 99,153 | $ 88,169 | $110,203 |
| Provision for income taxes[a] | 30,414 | 29,512 | 8,322 | — | — |
| Debt prepayment premium | — | — | — | — | 12,666 |
| Write-off of unamortized debt placement costs | — | — | — | — | 5,002 |
| Debt placement fee amortization | — | 253 | 9,950 | 2,830 | 3,056 |
| Interest expense, net | 25,329 | 12,113 | 21,758 | 34,536 | 35,435 |
| Depreciation and amortization | 31,746 | 35,767 | 35,096 | 36,081 | 41,845 |
| EBITDA | $136,391 | $145,517 | $174,279 | $161,616 | $208,207 |

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 | 2001 | 2002 | 2003 | 2004 |
| Petroleum products pipeline system: | | | | | |
| Transportation revenue per barrel shipped | $ 0.891 | $ 0.908 | $ 0.949 | $ 0.964 | $ 0.992 |
| Transportation barrels shipped (millions) | 229.1 | 236.1 | 234.6 | 237.6 | 253.6 |
| Petroleum products terminals: | | | | | |
| Marine terminal average storage capacity utilized per month (million barrels)[e] | 14.7 | 15.7 | 16.2 | 15.2 | 15.8 |
| Marine terminal throughput (million barrels)[f] | 3.7 | 11.5 | 20.5 | 22.2 | 28.9 |
| Inland terminal throughput (million barrels) | 56.1 | 56.7 | 57.3 | 61.2 | 101.2 |
| Ammonia pipeline system: | | | | | |
| Volume shipped (thousand tons) | 713 | 763 | 712 | 614 | 765 |

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

(e) For the year ended December 31, 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. 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 three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 43 terminals (a portion of which was acquired during October 2004 as discussed in *Significant Events* below);
- petroleum products terminals, which principally includes our six marine terminal facilities and 29 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

During April 2002, we acquired Magellan Pipeline Company, L.P. ("Magellan Pipeline") 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 interests. 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*

*Indemnification settlement*—During May 2004, we entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release them from certain indemnifications. The indemnifications primarily related to environmental items for periods during which Williams was the owner of assets we purchased from them. We received $35.0 million from Williams on July 1, 2004 and expect to receive the remaining balance in annual installments of $27.5 million, $20.0 million and $35.0 million in July of 2005, 2006 and 2007, respectively. See the *Environmental* section below for further discussion of this matter.

*Refinancing*—Also in May 2004, we took steps to increase our financial flexibility, which included the issuance of one million common units and $250.0 million of 10-year senior unsecured notes. We used the proceeds from these offerings primarily to refinance $268.0 million of existing secured debt. Further, we amended our remaining secured debt instruments to release the collateral, resulting in our current unsecured capital structure. See the *Liquidity* section below for further discussion of our new debt structure.

*Pipeline acquisition*—During June 2004, we announced our intention to acquire more than 2,000 miles of petroleum products pipeline system assets from affiliates of Shell Oil Products US ("Shell"). In anticipation of the transaction closing, we sold 1.8 million common units during August 2004 to assist with the acquisition funding. Net proceeds from this sale were $87.1 million, including our general partner's $1.8 million contribution to maintain its 2% general partner interest. We closed the acquisition on October 1, 2004, and paid approximately $487.4 million for the pipeline systems. In addition, we paid approximately $30.0 million for inventory related to a third-party supply agreement for which we received $14.0 million of cash collateral. Further, we assumed approximately $29.6 million of existing liabilities and expect to incur $9.6 million of transaction costs. We have incurred approximately $6.3 million of transaction costs through December 31, 2004.

At the closing, we financed the acquisition with: (i) cash on hand of approximately $173.7 million, including net proceeds of approximately $87.1 million from our August 2004 equity offering and net of an escrow payment of approximately $24.6 million to Shell in June 2004; (ii) $300.0 million of borrowings under a short-term acquisition facility; and (iii) $50.0 million of borrowings under our revolving credit facility. During October 2004, we issued and sold an additional 2.6 million common units for net proceeds of approximately $138.3 million, including our general partner's $2.9 million contribution to maintain its 2% general partner interest, and $250.0 million of unsecured notes for net proceeds of approximately $247.6 million. The proceeds from the equity and debt offerings were used primarily to repay the borrowings under our short-term acquisition facility and revolving credit facility. The underwriters exercised their over-allotment option associated with the October 2004 equity offering and on November 1, 2004, we issued and sold an additional 0.4 million common units. The net proceeds from this sale were approximately $20.8 million, including our general partner's $0.4 million contribution to maintain its 2% general partner interest, which replaced cash we used to pay for other investments.

We have accounted for the assets we acquired from Shell as an acquisition of assets for the following reasons: (i) the assets we acquired were not operated historically as a separate division or subsidiary. Shell operated these assets as part of its more extensive transportation and terminalling and crude oil and refined products operations. As a result, Shell did not maintain complete and separate financial statements for these assets as an independent business unit; (ii) we intend to make significant changes to the assets in the future, including construction of additional connections between the acquired assets and our existing infrastructure, which may result in significant operating differences and revenues generated; and (iii) differences in our operating approach may result in our obtaining different revenues and results of operations than those historically achieved by Shell. Beginning with fourth-quarter 2004, financial results from the majority of the acquired assets have been reported as part of our petroleum products pipeline system segment.

***Recent Developments***

On January 26, 2005, the board of directors of our general partner declared a quarterly cash distribution of $0.9125 per unit for the period of October 1 through December 31, 2004. Including this declaration, we paid distributions equal to $3.5225 per unit related to 2004 compared to $3.17 per unit related to 2003, an increase in excess of 11%. In addition, the $0.9125 per unit distribution represented a 74% increase compared to our $0.525 per unit distribution at the time of our initial public offering in February 2001. The quarterly distribution was paid on February 14, 2005 to unitholders of record on February 8, 2005.

In January 2005, Magellan Midstream Holdings ("MMH"), the owner of our general partner interest, sold 2,735,541 of our common units it held in a privately negotiated transaction. Further, in February 2005, MMH sold an additional 225,144 common units. Following these sales and the February 2005 conversion of a portion of our subordinated units, MMH owned 1,194,779 common units, 2,839,848 subordinated units and all of the ownership interests in our general partner, for a combined 14% ownership interest in us.

**Overview**

In 2004, our net cash from operating activities significantly exceeded our debt service obligations and cash distributions to our unitholders. Our petroleum products pipeline system generates a substantial portion of our cash flows. 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. Operating expenses are principally fixed costs related to routine maintenance and system integrity as well as field and support personnel. Other costs, including power, fluctuate with volumes transported and stored on the system. Expenses resulting from environmental remediation projects have historically included costs from projects relating both to current and past events. For further discussion of indemnified environmental matters, see “Business—Environmental” under Item 1 of this 10-K report.

We expect to maintain or grow the cash flows of our 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. (See “Risks Related to our Business” for other factors which could impact our operations and cash flows).

*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 and we also purchase transmix which we then fractionate and sell. Additionally, we purchased a petroleum products management operation from Williams in July 2003, and we take title to the associated inventories and resulting products from that operation. 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. In October 2004, as part of our acquisition of assets from Shell, we assumed a third-party supply agreement which requires us to buy and sell significant quantities of petroleum products. We routinely take title to these products under this agreement.

*Petroleum Products Terminals.* Within our terminals network, we operate two types of terminals: marine terminal facilities and inland terminals. The marine terminals 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 aviation fuel and filtering aviation fuel.

*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 significantly increased our operations over the past three years through the following acquisitions:

- in October 2004, the acquisition of a 2,000-mile petroleum products pipeline system;
- in March 2004, the acquisition of a 50% ownership interest in Osage Pipeline Company, LLC (“Osage Pipeline”);
- in January 2004, the acquisition of six inland terminals and the remaining 21% ownership interest in eight terminals;
- in July 2003, the acquisition of a petroleum products management business; and
- in April 2002, the acquisition of a 6,700-mile petroleum products pipeline system.

**Results of Operations**

We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure used by management to evaluate the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and general and administrative ("G&A") costs, which management does not consider when evaluating the core profitability of an operation.

Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below.

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

| | Year Ended December 31, 2003 | Year Ended December 31, 2004 |
|---|---|---|
| **Financial Highlights (in millions)** | | |
| Revenues: | | |
| Transportation and terminals revenue: | | |
| Petroleum products pipeline system | $281.4 | $312.3 |
| Petroleum products terminals | 78.9 | 91.3 |
| Ammonia pipeline system | 12.6 | 13.9 |
| Intersegment eliminations | — | (1.1) |
| Total transportation and terminals revenue | 372.9 | 416.4 |
| Product sales | 112.3 | 278.5 |
| Affiliate management fees | — | 0.5 |
| Total revenues | 485.2 | 695.4 |
| Operating expenses, environmental expenses and environmental reimbursements: | | |
| Petroleum products pipeline system | 128.5 | 140.1 |
| Petroleum products terminals | 34.7 | 37.1 |
| Ammonia pipeline system | 4.5 | 6.6 |
| Intersegment eliminations | (0.8) | (4.2) |
| Total operating expenses, environmental expenses and environmental reimbursements | 166.9 | 179.6 |
| Product purchases | 99.9 | 255.7 |
| Equity earnings | — | (1.6) |
| Operating margin | 218.4 | 261.7 |
| Depreciation and amortization | 36.1 | 41.8 |
| Affiliate G&A expenses | 56.9 | 54.5 |
| Operating profit | $125.4 | $165.4 |
| **Operating Statistics** | | |
| Petroleum products pipeline system: | | |
| Transportation revenue per barrel shipped | $0.964 | $0.992 |
| Transportation barrels shipped (million barrels) | 237.6 | 253.6 |
| Petroleum products terminals: | | |
| Marine terminal facilities: | | |
| Average storage capacity utilized per month (barrels in millions) | 15.2 | 15.8 |
| Throughput (barrels in millions) | 22.2 | 28.9 |
| Inland terminals: | | |
| Throughput (barrels in millions) | 61.2 | 101.2 |
| Ammonia pipeline system: | | |
| Volume shipped (tons in thousands) | 614 | 765 |

Transportation and terminals revenues for the year ended December 31, 2004 were $416.4 million compared to $372.9 million for the year ended December 31, 2003, an increase of $43.5 million, or 12%. This increase was a result of:

- an increase in petroleum products pipeline system revenues of $30.9 million, or 11%, primarily attributable to additional revenues from our October 2004 pipeline system acquisition and significantly higher diesel and aviation fuel volume shipments on our existing pipeline system during the current period resulting from increased market demand due to the improving U.S. economy. Further, management fee income associated with our operation of the Longhorn pipeline beginning in 2004 and higher additive and tank lease revenues also contributed to the revenue increase;
- an increase in petroleum products terminals revenues of $12.4 million, or 16%, primarily due to additional revenues from our acquisition of ownership interests in 14 inland terminals during January 2004 and our new marine terminal in East Houston, Texas, which was acquired as part of the pipeline system acquisition during fourth-quarter 2004. Further, higher utilization and rates at our marine terminals and increased throughput at our other inland terminals benefited the 2004 period; and
- an increase in ammonia pipeline system revenues of $1.3 million, or 10%, primarily due to significantly increased transportation volumes during the current year. Volumes increased in the current year primarily due to the implementation of a proportional credit program during late 2003 and higher farm commodity prices which increased demand for ammonia fertilizer.

Operating expenses, environmental expenses and environmental reimbursements combined were $179.6 million for the year ended December 31, 2004 compared to $166.9 million for the year ended December 31, 2003, an increase of $12.7 million, or 8%. By business segment, this increase was principally the result of:

- an increase in petroleum products pipeline system expenses of $11.6 million, or 9%, primarily attributable to operating costs associated with the pipeline system acquired in October 2004, unfavorable product loss allowances, asset retirements, higher allocated depreciation that is charged as an operating expense since third-quarter 2003, increased asset integrity costs and higher insurance expenses. These increases were partially offset by lower employee costs due to a benefits accrual recorded during 2003 associated with the change in control of our general partner;
- an increase in petroleum products terminals expenses of $2.4 million, or 7%, primarily due to operating costs associated with acquisition of the ownership interests in 14 inland terminals and the East Houston marine terminal. These increases were partially offset by reduced asset retirements and lower employee costs due to a benefits accrual recorded during 2003 associated with the change in control of our general partner;
- an increase in ammonia pipeline system expenses of $2.1 million, or 47%, primarily attributable to higher system integrity costs and environmental accruals, partially offset by lower property tax assessments during 2004; and
- an increase in intersegment eliminations of $3.4 million primarily due to higher allocations of corporate depreciation to the business segments as an operating expense. We did not have depreciable assets recorded at the partnership level until third-quarter 2003.

Revenues from product sales were $278.5 million for the year ended December 31, 2004, while product purchases were $255.7 million, resulting in a difference of $22.8 million. The difference between product sales and purchases in 2004 increased $10.4 million as compared to the difference between products sales and purchases in 2003 of $12.4 million resulting from product sales for the year ended December 31, 2003 of $112.3 million and product purchases of $99.9 million. The increase in 2004 primarily reflects increased product sales from our acquisition of the petroleum products management operation in July 2003. The amount of product sales and product purchases increased substantially during 2004 primarily as a result of the third-party supply agreement assumed as part of the assets we acquired from Shell during October 2004. We expect the annual amount of product sales and purchases to increase in the future reflecting a full-year of this agreement although the difference between product sales and purchases may remain substantially similar to 2004 results.

Equity earnings were $1.6 million during the year ended December 31, 2004 as a result of our acquisition of a 50% interest in Osage Pipeline during March 2004.

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

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

- $2.1 million lower incentive compensation expense during 2004, primarily because of the early vesting of restricted units under our long-term incentive plan that was triggered by the 2003 change in control of our general partner; and
- $5.0 million lower transition costs associated with the separation of our G&A functions from Williams. During 2003, the transition costs were $5.8 million, which principally included a benefits accrual and creation of our stand-alone information technology functions. Comparatively, the 2004 period included $0.8 million of transition costs. We do not anticipate incurring any further transition costs related to our separation from Williams.

Partially offsetting these decreases was an increase in the amount of affiliate G&A expense we record. Our general partner provides G&A services to us for an established G&A amount, which we refer to as the G&A cap. The owner of our general partner is responsible for G&A expenses in excess of this G&A cap up to a certain amount. We record total G&A costs, including those costs above the cap amount that are reimbursed by the owner of our general partner, as an expense, and we record the amount in excess of the G&A cap for which we are reimbursed as a capital contribution by our general partner. When Williams owned our general partner, we were unable to identify specific costs required to support our operations. As a result, we recorded only the G&A costs under the G&A cap as expense, which reflected our actual cash costs. Due to the change in our organizational structure following the change in control of our general partner in June 2003, we are now able to clearly identify all G&A costs required. For 2004 and 2003, the G&A cap was $41.8 million and $38.2 million, respectively. Based on the agreement with our general partner, the amount of G&A costs we pay increases by 7% annually and by incremental G&A expenses related to completed acquisitions. The G&A cap is expected to be $49.3 million during 2005.

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

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

Net income for the year ended December 31, 2004 was $110.2 million compared to $88.2 million for the year ended December 31, 2003, an increase of $22.0 million, or 25%. Operating margin increased by $43.3 million, or 20%, primarily due to incremental operating results associated with our recent acquisitions and improved utilization of our other assets. Operating margin also improved during the current period due to lower operating expense transition costs associated with the change in control of our general partner in 2004 as compared to 2003. Depreciation and amortization expense increased by $5.7 million between periods, while G&A costs decreased by $2.4 million. Net interest expense increased by $0.9 million, and we incurred $16.7 million of refinancing costs during the current period.

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

| | Year Ended December 31, 2002 | Year Ended December 31, 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 |
| Intersegment 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 G&A expenses | 43.2 | 56.9 |
| Operating profit | $137.1 | $125.4 |
| **Operating Statistics** | | |
| Petroleum products pipeline system: | | |
| Transportation revenue per barrel shipped | $0.949 | $0.964 |
| Transportation barrels shipped (million barrels) | 234.6 | 237.6 |
| 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 increased capacity leases 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 customer's storage agreement at our Galena Park, Texas facility during the first quarter of 2003. Increased revenues from the resulting $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 a 2003 benefits accrual for operations employees related to the change in control 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 the $2.6 million 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 property 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 benefits accrual and increased property 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 had 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 difference of $12.4 million. The difference between product sales and purchases in 2003 increased $5.8 million as compared to the difference between product sales and purchases 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 increased product sales 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 annual fee rather than from buying and selling petroleum products.

Depreciation and amortization expense was $36.1 million for the year ended December 31, 2003 compared to $35.1 million for the year ended December 31, 2003, an increase of $1.0 million, or 3%, primarily due to the additional depreciation associated with acquisitions and capital improvements.

Affiliate 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%. This increase was primarily attributable to the following items:

- $7.4 million of one-time costs resulting from the change in ownership of our general partner during 2003:
  - › $5.8 million of transition costs associated with the separation of our G&A functions from Williams. The transition costs primarily included the creation of our stand-alone information technology functions and a benefits accrual related to G&A employees; and
  - › $1.6 million of incentive compensation expense related to the early vesting of restricted units under our long-term incentive plan that was triggered by the 2003 change in control of our general partner; and
- $5.9 million of G&A costs during the 2003 period above a cap that will be reimbursed by our general partner. Prior to the change in control of our general partner, we were unable to identify specific costs required to support our operations; consequently, we recorded G&A costs only up to the G&A cap as our expense, which reflected our actual cash cost.

Interest expense, net of interest income, for the year ended December 31, 2003 was $34.5 million compared to $21.8 million for the year ended December 31, 2002, an increase of $12.7 million, or 58%. The increase in interest expense was primarily related to the fourth-quarter 2002 replacement of short-term debt financing associated with the acquisition of the original segment of our petroleum products pipeline system with long-term debt at higher interest rates. The weighted-average interest rate on our borrowings increased from 4.6% in 2002 to 6.3% in 2003 with the average debt outstanding increasing from $522.0 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, a $7.1 million decline. During the 2002 period, the short-term debt associated with our acquisition of the original segment of our 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%. Operating margin increased by $3.0 million over the prior year, despite $3.4 million of one-time operating expense items associated with the change in control of our general partner, largely as a result of increased transportation volumes and rates on our petroleum products pipeline system, increased differences between product sales and purchases 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 amortization expense increased by $1.0 million, and G&A costs increased by $13.7 million, primarily due to one-time costs associated with the change in control of our general partner and reimbursable G&A costs. Net interest expense increased by $12.7 million, 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, and income taxes decreased $8.3 million due to our partnership structure.

### Liquidity and Capital Resources

*Cash Flows and Capital Expenditures*

During 2004, net cash provided by operating activities exceeded distributions paid and net maintenance capital requirements by $101.3 million, and our cash distributions exceeded the minimum quarterly distribution of $0.525 per unit by $54.6 million.

Net cash provided by operating activities was $236.5 million for the year ended December 31, 2004, $144.0 million for 2003 and $161.0 million for 2002.

- The $92.5 million increase from 2003 to 2004 was primarily attributable to:
  - › increased net income of $22.0 million including results from our operations associated with the assets acquired from Shell in the fourth quarter of 2004;
  - › a $12.7 million prepayment premium during 2004 on our Magellan Pipeline Series A senior notes, which reduced net income but has been classified as cash from financing activities;
  - › collection of $35.0 million from Williams during 2004 related to our indemnification settlement agreement;
  - › an increase in our equity-based incentive compensation liability in 2004 versus 2003 of $9.3 million primarily due to the settlement of awards during 2003 related to the change in ownership of our general partner;
  - › $10.1 million lower cash payments in 2004 as compared to payments made during 2003 associated with our separation from Williams; and
  - › a net increase in accounts receivable of $16.6 million primarily due to increased accounts receivable resulting from the supply agreement assumed in connection with the assets acquired from Shell. This increase was largely offset by the receipt of $14.0 million of cash collateral from the supply agreement customer.
- The $17.0 million decrease from 2002 to 2003 was primarily attributable to:
  - › reduced net income of $11.0 million principally resulting from the costs related to the 2003 change in control of our general partner;
  - › an increase in inventory of $12.1 million during 2003 resulting from our July 2003 purchase of a petroleum products management operation. A corresponding increase in accrued product purchases of $8.5 million partially offset the inventory change; and
  - › non-cash expenses associated with the change of control of our general partner in 2003 were generally offset by changes in our affiliate assets and liabilities.

Net cash used by investing activities for the years ended December 31, 2004, 2003 and 2002 was $712.3 million, $45.9 million and $727.0 million, respectively. During 2004, our net investments in marketable securities were $87.8 million. In addition, we acquired: (i) ownership in 14 petroleum products terminals located in the southeastern United States for $25.4 million; (ii) a 50% ownership in Osage Pipeline for $25.0 million; and (iii) petroleum products pipeline system assets from Shell for $487.4 million plus $6.3 million of incurred transaction costs and $30.0 million for inventory. During 2003, we acquired our petroleum products management operation. During 2002, we acquired Magellan Pipeline. Total maintenance capital spending before reimbursements was $21.9 million, $20.9 million and $26.4 million in 2004, 2003 and 2002, 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, 2004, 2003 and 2002 was $394.3 million, $(61.8) million and $627.3 million, respectively. Cash provided during 2004 principally included the debt and equity financings that were completed in conjunction with our acquisition of assets from Shell, partially offset by the repayment of debt in connection with our May 2004 refinancing and cash distributions paid. Cash was used during 2003 primarily to pay cash distributions to our unitholders. Cash provided during 2002 principally included the debt and equity offerings that were completed in conjunction with our acquisition of Magellan Pipeline, partially offset by cash distributions paid.

During 2004, we paid $116.9 million in cash distributions to our unitholders. The quarterly distribution amount associated with the fourth quarter of 2004 was $0.9125 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 $141.9 million will be paid to our unitholders in 2005. Of this amount, $20.8 million, or 15%, would be related to our general partner's 2% ownership interest and incentive distribution rights. In connection with the October 2004 acquisition of assets from Shell, our partnership agreement was amended to reduce the incentive cash distributions paid to our general partner by $5.0 million in 2005 and $3.0 million in 2006. Without this amendment, the amounts paid to our general partner in 2005, assuming the current quarterly distribution level of $0.9125, would be $25.8 million and total distributions would be $146.9 million.

*Capital Requirements*

Our businesses require continual investment to upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending for our businesses 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, referred to as organic growth projects. Organic growth projects include capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During 2004, our maintenance capital spending net of reimbursable projects was $18.3 million. In addition, we were reimbursed $3.6 million for the following projects during 2004, resulting in no cash impact to us:

- $2.3 million of reimbursable environmental projects covered by the indemnity settlement with Williams, with the first settlement payment of $35.0 million received from Williams in July 2004;
- $0.9 million of reimbursements from the U.S. government associated with grants for security enhancements at our marine terminal facilities; and
- $0.4 million of reimbursements from our general partner for the remaining transition costs associated with our separation from Williams.

For 2005, we expect to incur maintenance capital expenditures net of reimbursable projects for our existing businesses of approximately $25.0 million. This increased spending expectation primarily relates to maintenance needs of the assets we acquired from Shell in October 2004, as well as higher costs due in part to timing of integrity work and upgrades to our operating systems.

In addition to maintenance capital expenditures, we also incur payout capital expenditures at our existing facilities. During 2004, we spent approximately $29.5 million for organic growth opportunities and $574.9 million for acquisitions. Based on projects currently in process, we plan to spend approximately $30.0 million on organic growth payout capital during 2005, exclusive of amounts associated with future acquisitions.

*Liquidity*

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

In May 2004, we completed a refinancing plan that improved our financial flexibility by providing for the release of the collateral previously securing our debt. This refinancing plan further served to reduce the weighted-average interest rate we incur and lowered our outstanding debt. In October 2004, we borrowed $300.0 million under a short-term acquisition facility and $50.0 million under our revolving credit facility to partially finance the assets acquired from Shell. We repaid these borrowings in October 2004 using proceeds from public debt and equity offerings. Our short-term acquisition facility was cancelled at that time. As of December 31, 2004, we had $804.7 million of total debt outstanding.

*5.65% Senior Notes due 2016.* On October 15, 2004, we sold $250.0 million of 5.65% senior notes due 2016 in an underwritten public offering as part of the long-term financing of the assets acquired from Shell. The notes were issued at 99.9% of par, and we received proceeds after underwriters' fees and expenses of approximately $247.6 million. Including the impact of pre-issuance hedges associated with these notes and the swap of $100.0 million of the notes from fixed-rate to floating-rate, the weighted average interest rate on the notes for 2004 was 5.1%.

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

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

*Magellan Pipeline Senior Secured Notes.* In connection with the long-term financing of our acquisition of Magellan Pipeline, we and Magellan Pipeline entered into a note purchase agreement on October 1, 2002. The $480.0 million borrowed under this agreement included Series A and Series B senior notes. The Series A senior notes included $178.0 million of borrowings that incurred interest based on the six-month Eurodollar rate plus 4.3%. The Series B senior notes included $302.0 million of borrowings that incur interest at a weighted-average fixed rate of 7.7%. The maturity date of these notes is October 7, 2007, with scheduled prepayments equal to 5% of the outstanding balance on both October 7, 2005 and October 7, 2006. We guarantee payment of interest and principal by Magellan Pipeline. Our membership interests in and the assets of Magellan Pipeline initially secured this debt.

As a result of our May 2004 refinancing, we repaid the $178.0 million outstanding balance of the Series A senior notes and we incurred $12.7 million of associated prepayment premiums. Further, in exchange for a $1.9 million payment, the Series B noteholders released the collateral that secured these notes, except for cash deposited monthly by Magellan Pipeline into a cash escrow account in anticipation of semi-annual interest payments. Including the impact of the swap of $250.0 million of the Series B senior notes from fixed-rate to floating-rate, the weighted average interest rate for the Series A and Series B senior notes combined was approximately 6.6% for the year ended December 31, 2004. The weighted-average interest rate for the Series B senior notes, including the impact of the interest rate swaps, was approximately 6.9% for the year ended December 31, 2004.

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

*Revolving Credit Facility.* In connection with our May 2004 refinancing, we entered into a five-year $125.0 million revolving credit facility, which we subsequently increased to $175.0 million in September 2004. Borrowings under this facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.6% to 1.5% based upon our credit ratings. As of December 31, 2004, $1.1 million of the facility was obligated for letters of credit, with no other amounts outstanding.

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

Management uses interest rate derivatives to manage interest rate risk. In conjunction with our existing debt instruments, we were engaged in the following derivative transactions as of December 31, 2004:

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

*Debt-to-Total Capitalization*. The ratio of debt-to-total capitalization is a measure frequently used by the financial community to assess the reasonableness of a company's debt levels compared to its total capitalization, which is calculated by adding total debt and total partners' capital. Based on the figures shown in our balance sheet, debt-to-total capitalization was 50% at December 31, 2004. Because accounting rules required the acquisition of a portion of Magellan Pipeline to be recorded at historical book values due to the then affiliate nature of the transaction, the $474.5 million difference between the purchase price and book value at the time of the acquisition was recorded as a decrease to our general partner's capital account, thus lowering our overall partners' capital by that amount.

**Off-Balance Sheet Arrangements**

None

### Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2004 (in millions):

| | Total | < 1 year | 1-3 years | 3-5 years | > 5 years |
|---|---|---|---|---|---|
| Long-term and current debt obligations(1) | $ 802.0 | $ 15.1 | $286.9 | $ — | $500.0 |
| Interest obligations | 383.8 | 54.0 | 99.7 | 61.3 | 168.8 |
| Operating lease obligations | 23.5 | 2.6 | 5.4 | 3.4 | 12.1 |
| Pension and post-retirement medical obligations | 14.7 | 1.5 | 0.6 | 0.9 | 11.7 |
| Purchase commitments: | | | | | |
| Affiliate operating and G&A(2) | | | | | |
| Petroleum product purchases(3) | 66.6 | 66.6 | — | — | — |
| Derivative financial instruments(4) | | | | | |
| Long-term incentive awards(5) | 7.1 | 0.5 | 6.6 | — | — |
| Capital project purchase obligations | 11.0 | 11.0 | — | — | — |
| Other purchase obligations | 5.2 | 5.1 | 0.1 | — | — |
| Other | 14.0 | — | — | 14.0 | — |
| Total | $1,327.9 | $156.4 | $399.3 | $79.6 | $692.6 |

(1) Excludes market value adjustments to long-term debt associated with qualifying hedges.

(2) 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 in June 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 requirement to pay only MMH's costs as they are incurred, we are unable to determine the actual amount of this commitment. The amount we paid MMH for operating and G&A costs during 2004, net of G&A reimbursements, was $106.9 million. However, additional operating and G&A costs associated with our acquisition of assets from Shell during the fourth quarter of 2004 should cause these amounts to increase during 2005 and beyond.

(3) We have an agreement to supply a customer with approximately 550 thousand barrels of petroleum products per month until the agreement expires in 2018. Related to this supply agreement, we have entered into certain forward contracts to purchase various petroleum products based on pricing structures during the first quarter of 2005. This amount is an estimated value of our product purchase commitments based on projected prices during the first quarter of 2005.

(4) On December 31, 2004, we had outstanding interest rate swap agreements to hedge against the fair value of $350.0 million of our long-term debt. Because future cash outflows under these agreements, if any, are uncertain, they have been excluded from this table.

(5) Represents amounts we have accrued for long-term incentive compensation through December 31, 2004 based on when those existing liabilities will be settled. We expect the amounts that will ultimately vest to our employees will exceed these amounts due to anticipated compensation liabilities that will be recognized over the remainder of the vesting periods and changes in our unit prices between December 31, 2004 and the date the unit awards actually vest.

### Environmental

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

Prior to May 2004, Williams provided indemnifications to us for assets we previously acquired from them. The indemnifications primarily related to environmental items for periods during which Williams was the owner of those assets. In May 2004, we entered into an agreement with Williams under which they agreed to pay us $117.5 million to release them from those indemnification obligations. We received $35.0 million from Williams on July 1, 2004 and expect to receive the remaining balance in annual installments of $27.5 million, $20.0 million and $35.0 million in July of 2005, 2006 and 2007, respectively. As of December 31, 2004, known liabilities that would have been covered by these indemnifications were $40.8 million. In addition, we have incurred $7.2 million of expenditures through December 31, 2004 that would have been covered by these indemnifications.

Further, MMH has indemnified us against certain environmental liabilities. At the time of MMH's purchase of Williams' ownership in us, MMH assumed obligations to indemnify us for $21.9 million of known environmental liabilities. Through December 31, 2004, we have incurred $11.5 million of costs associated with this indemnification obligation, leaving a remaining liability of $10.4 million. Our receivable balance with MMH on December 31, 2004 was $11.5 million.

**Other Items**

We ship ammonia for three customers on our ammonia pipeline system. The transportation agreements we have with these three customers expire at the end of June 2005. We are currently negotiating the terms of new transportation contracts to be effective in July 2005. If we are unsuccessful in renegotiating these contracts, it could have a significant impact on our revenues and results of operations after the current contracts expire.

**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 through increased costs to our customers in the form of higher fees.

**Critical Accounting Estimates**

Our management has discussed the development and selection of the following critical accounting estimates with the Audit Committee of our general partner's Board of Directors and the Audit Committee has reviewed and approved these disclosures.

***Environmental Liabilities***

We estimate the liabilities associated with environmental expenditures based on site-specific project plans for remediation, taking into account prior remediation experience. Remediation project managers evaluate each known case of environmental liability to determine what associated costs can be reasonably estimated and to ensure compliance with all applicable federal and state requirements. We believe the accounting estimate relative to environmental remediation costs to be a "critical accounting estimate" because: (1) estimated expenditures, which will generally be made over the next 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 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 completion.

Each quarter, we re-evaluate our environmental estimates taking into account any new incidents that have occurred since the last annual meeting of the remediation project managers, any changes in the site situation and additional findings or changes in federal or state regulations. The estimated environmental liability accruals are adjusted as necessary. Changes in our environmental liabilities since December 31, 2002 are as follows (in millions):

| Balance | 2003 | | Balance | 2004 | | Balance |
|---|---|---|---|---|---|---|
| 12-31-02 | Accruals | Expenditures | 12-31-03 | Accruals | Expenditures | 12-31-04 |
| $22.3 | $13.9 | $(9.4) | $26.8 | $49.9 | $(15.9) | $60.8 |

During the fourth quarter of 2003, we experienced a leak on our petroleum products pipeline near Kansas City, Kansas, which resulted in an initial increase to our environmental liabilities of $4.8 million. We expected insurance proceeds to cover $3.1 million of these costs and we charged the remaining $1.7 million against 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 on our operating profit or net income because most of the increases were covered by indemnities from Williams or insurance.

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

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

Our known environmental liabilities at December 31, 2004 are based on estimates that are subject to change, and any changes to these estimates would impact our results of operations and financial position. For example, if our environmental liabilities increased by as much as 15% and assuming that none of this increase was covered by indemnifications or insurance, our expenses would increase by $9.1 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 6% of our operating profit and 8% of our net income for 2004. 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 $0.26. Such a change would increase our liabilities and decrease equity by approximately 1%. The impact of such an increase in environmental costs would likely not affect our liquidity because, even with the increased costs, we would still comply with the covenants of our long-term debt agreements as discussed above under "Liquidity and Capital Resources—Liquidity".

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

Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. Straight-line depreciation results in depreciation expense being incurred evenly over the life of the asset. At December 31, 2003 and 2004, the net book value of our property, plant and equipment was $0.9 billion and $1.5 billion, respectively and we recorded depreciation expense of $35.3 million and $40.5 million during 2003 and 2004, respectively.

The determination of an asset's estimated useful life takes a number of factors into consideration, including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and result in an increase or decrease in depreciation expense. Our terminals, pipelines and related equipment have estimated useful lives of three to 59 years, with a weighted-average asset life of approximately 40 years. If the estimates of our asset lives changed such that the average estimated asset life was 35 years, our depreciation expense for 2004 would increase by $7.6 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 5% of our operating profit and 7% of our net income for 2004. 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 $0.22. Such a change would decrease total assets by less than 1% and equity by approximately 1%. The impact of such an increase in depreciation costs would likely not have affected our liquidity because, even with the increased costs, we would still comply with the covenants of our long-term debt agreements as discussed above under "Liquidity and Capital Resources—Liquidity".

**New Accounting Pronouncements**

In December 2004, the Financial Accounting Standards Board ("FASB") issued a revision to Statement of Financial Accounting Standard ("SFAS") No. 123, "Share-Based Payment", referred to as "SFAS No. 123R". This Statement establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. This revision requires that all equity-based compensation awards to employees be recognized in the income statement based on their fair values, eliminating the alternative to use Accounting Principle Board ("APB") No. 25's intrinsic value method. The standard is effective as of the beginning of the first interim period that begins after June 15, 2005. This Statement applies to all awards granted after the required effective date but is not to be applied to awards granted in periods before the required effective date except to the extent that awards from prior periods are modified, repurchased or cancelled after the required effective date. We intend to adopt the Statement on July 1, 2005, using the modified prospective application method. Under the modified prospective method we will be required to account for all of our equity-based incentive awards granted prior to June 30, 2005 using the fair value method as defined in SFAS No. 123 instead of our current methodology of using the intrinsic value method as defined in APB No. 25. Our existing equity-based awards are stock appreciation rights, as defined in FASB Interpretation ("FIN") No. 28. As such, we recognize compensation expense under APB No. 25/FIN No. 28 in much the same manner as that required under SFAS No. 123. Consequently, the initial adoption and application of SFAS No. 123R will not have a material impact on our financial position, results of operations or cash flows.

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

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

In December 2003, the 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 additional disclosure requirements of this Statement were effective for quarters beginning after December 15, 2003 and for fiscal years ending 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 was effective for financial instruments entered into or modified after May 31, 2003, and otherwise was 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.

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 and for hedging activities under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”. The application of this Statement did not have a material impact on our financial position, results of operations or cash flows upon its initial adoption.

In April 2003, the FASB issued FIN No. 46, “Consolidation of Variable Interest Entities.” The interpretation included a new consolidation model, the variable interest model, which determines control and consolidation based on potential variability in gains and losses of the entity being evaluated for consolidation. FIN No. 46 requires that all entities, with limited exceptions, be evaluated to determine whether or not they are variable interest entities (“VIEs”). All VIEs then are evaluated for consolidation based on their variable interests. The party with the majority of the variability in gains and losses of the VIE is the VIE’s primary beneficiary and is required to consolidate the VIE. The interpretation’s provisions were effective for enterprises with variable interests in VIE’s created after January 31, 2003. The application of FIN No. 46 had no impact on our financial position, results of operations or cash flows.

**Related Party Transactions**

Through June 17, 2003, affiliate revenues represented revenues from Williams and its affiliates. Affiliate revenues during 2002 and 2003 primarily included pipeline and terminal storage revenues, ancillary service revenues for our marine facilities, fee income related to petroleum products asset management activities and certain software licensing fees. Sales to affiliates of Williams were at prices consistent with those charged to non-affiliate entities. Revenues from affiliates of Williams are summarized in the table below (in millions):

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| Revenues from affiliates of Williams | $ 58.6 | $ 13.9 | $ — |
| Total revenues | $434.5 | $485.2 | $695.4 |
| Revenues from affiliates of Williams as a percent of total revenue | 13% | 3% | 0% |

In March 2004 we acquired a 50% ownership interest in Osage Pipeline. We operate the Osage pipeline and receive a fee for these services. During 2004 we received $0.5 million from Osage Pipeline for operating fees, which we reported as affiliate revenues. We also received $0.3 million from Osage for fees to transition accounting, billing and other administrative functions to us. These fees were recorded as other income, which is netted into operating expense in our results of operations.

MMH, which owns our general partner, is partially owned by an affiliate of the Carlyle/Riverstone Global Energy and Power Fund II, L.P., (the "Carlyle/Riverstone Fund"). Two of the members of our general partner's eight-member board of directors are nominees of the Carlyle/Riverstone Fund. On January 25, 2005, the Carlyle/Riverstone Fund, through affiliates, acquired an interest in the general partner of SemGroup, L.P. ("SemGroup") and limited partner interests in SemGroup. The Carlyle/Riverstone Fund's total combined general and limited partner interest in SemGroup is approximately 30%. Three of the members of SemGroup's general partner's nine-member board of directors are nominees of the Carlyle/Riverstone Fund. We, through our affiliates, are parties to a number of transactions with SemGroup and its affiliates. These transactions include leasing storage tanks to and from SemGroup, buying and selling petroleum products from and to SemGroup and transporting petroleum products for SemGroup. The board of directors of our general partner has adopted a Board of Directors Conflict of Interest Policy and Procedures. In compliance with this policy, the Carlyle/Riverstone Fund has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to SemGroup. As part of these procedures, the Carlyle/Riverstone Fund has agreed that no individual representing them will serve at the same time on our general partner's board of directors and on SemGroup's general partner's board of directors.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives increasing percentages of our distributions. Distributions to our general partner above the highest target level are at 50%. As the owner of our general partner, MMH indirectly benefits from these distributions. Through ownership of the Class B common units of MMH, which total 6% of the total ownership of MMH, certain executive officers of our general partner also indirectly benefit from these distributions. In 2004, distributions paid to our general partner totaled $16.7 million. In addition, during 2004, MMH received distributions totaling $28.7 million related to its common and subordinated units. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.9125 per unit, our general partner would receive distributions of approximately $20.8 million in 2005 on its combined 2% general partner interest and incentive distributions. Additionally, MMH would receive $14.9 million on the distribution related to its common and subordinated units. In connection with our October 2004 acquisition of the assets from Shell, our partnership agreement was amended to reduce the incentive cash distributions to be paid to our general partner by $5.0 million for 2005. Absent this agreement, the total distribution and combined general partner interest and incentive distribution amounts noted above in 2005 would be $5.0 million higher.

Costs and expenses related to activities between Williams and its affiliates and us after June 17, 2003, have been accounted for as unaffiliated third-party transactions. Transactions after June 17, 2003 between us and MMH and its affiliates have been accounted for as affiliate transactions. 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, | | |
|---|---|---|---|
| | 2002 | 2003 | 2004 |
| Affiliates of Williams—allocated G&A expenses | $ 43,182 | $23,880 | $ — |
| Affiliates of Williams—allocated operating expenses | 156,464 | 68,079 | — |
| Affiliates of Williams—product purchases | 22,268 | 472 | — |
| MMH—allocated operating expenses | — | 98,804 | 58,777 |
| MMH—allocated G&A expenses | — | 32,966 | 54,466 |

In 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated both direct and indirect G&A expenses to our general partner. Direct expenses allocated by Williams were primarily salaries and benefits of employees and officers associated with our businesses. Indirect expenses included legal, accounting, treasury, engineering, information technology and other corporate services. Williams allocated these expenses to our general partner based on an agreed-upon expense limitation. The additional G&A costs incurred but not reimbursed by Williams totaled $19.7 million in 2002 and $5.2 million for the period January 1, 2003 through June 17, 2003. The G&A costs allocated from Williams for the periods discussed above included a number of costs that were not specific to our businesses and therefore cannot be used as an estimate of our G&A costs during those periods. Additionally, in 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated operating expenses to our general partner. Expenses included all costs directly associated with our operations. On June 17, 2003, Williams' ownership in us was sold to MMH. As a result, we entered into a new services agreement with MMH pursuant to which MMH agreed to perform specified services required for our operations. Consequently, our G&A services are now provided by MMH and we now reimburse MMH for those costs, subject to the limitations as defined in the New Omnibus Agreement (see *Reimbursement of G&A Expense* below) The additional G&A costs incurred but not reimbursed by MMH are discussed below under *Reimbursement of G&A Expense.* From June 17, 2003 through December 31, 2003 operating expenses were allocated to our general partner from MMH.

Williams agreed to reimburse us for maintenance capital expenditures incurred in 2002 in excess of $4.9 million related to the assets contributed to us at the time of our initial public offering. During 2002, we recorded reimbursements from Williams associated with these assets of $11.0 million.

Williams and certain of its affiliates had indemnified us against certain environmental costs. The environmental indemnifications we had with Williams were settled during 2004. See discussion under "Environmental" above for information relative to our settlement of these indemnifications with Williams. Receivables from Williams or its affiliates associated with those environmental costs were $7.8 million at December 31, 2003, and were included with accounts receivable amounts presented in the consolidated balance sheets. In addition, MMH has indemnified us against certain environmental costs. Receivables from MMH were $19.0 million and $11.5 million at December 31, 2003 and 2004, respectively, and are included with the affiliate accounts receivable in the consolidated balance sheets.

*Reimbursement of G&A Expense*

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

- The reimbursement obligation is subject to a lower cap amount, which is calculated as follows:
    - For the period June 18, 2003 through December 31, 2003, MMH reimbursed us $6.0 million for G&A costs in excess of a lower cap amount;
    - For each succeeding fiscal year, the lower cap is adjusted by the greater of: (i) 7%, or (ii) the percentage increase in the Consumer Price Index—All Urban Consumers, U.S. City Average, Not Seasonally Adjusted. The reimbursement amount is also adjusted for acquisitions, construction projects, capital improvements, replacements or expansions that we complete that are expected to increase our G&A costs. During 2004, MMH reimbursed us $6.4 million for G&A costs in excess of the lower cap amount of $41.8 million;
    - Additionally, the expense reimbursement limitation excludes: (i) expenses associated with equity-based incentive compensation plans and (ii) implementation costs associated with changing our name and expenses and capital expenditures associated with transitioning the assets, operations and employees from Williams to MMH or us.

- The reimbursement limitation is further subject to an upper cap amount. MMH is not required to reimburse us for any G&A expenses that exceed this upper cap amount. The upper cap is calculated as follows:
  - For the period of June 18, 2003 through December 31, 2003, the upper cap was approximately $26.6 million, which represents an annual upper cap amount of $49.3 million pro-rated for the period from June 18, 2003 through December 31, 2003; and
  - For each succeeding fiscal year, the upper cap is increased annually by the lesser of: (i) 2.5%, or (ii) the percentage increase in the Consumer Price Index—All Urban Consumers, U.S. City Average, Not Seasonally Adjusted. The upper cap will also be adjusted for acquisitions, construction projects and capital improvements, replacements or expansions that we complete that are expected to increase our G&A costs. For 2004, the upper cap was adjusted to $51.5 million.

**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.

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;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates implemented by the FERC and the United States 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 the 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;
- 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 withholding issues, safety, environmental and employment laws and regulations;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or could have other adverse consequences;
- the condition of the capital markets in the United States;
- the effect of changes in accounting policies;
- the potential that internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact that could have on our unit price;
- our ability to manage rapid growth;
- MMH's ability to perform on its environmental and G&A reimbursement obligations to us;
- Williams' ability to pay the amounts owed to us under the indemnification settlement;
- the ability of our general partner to enter into certain agreements which could negatively impact our financial position, results of operations and cash flows;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

**Risks Related to our Business**

*We may not be able to generate sufficient cash from operations to allow us to pay quarterly distributions at current levels following establishment of cash reserves and payment of fees and expenses, including payments to our 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 quarterly distributions at the current level for each quarter. Our ability to pay quarterly distributions depends primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, we may 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 terminals and distribute through our inland terminals, and thereby reduce our cash flow and our ability to pay cash distributions. Factors that could lead to a decrease in market demand include:

- an increase in the market price of 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, aviation fuel and diesel;
- higher fuel taxes or other governmental or regulatory actions that increase the cost of gasoline;
- an increase in fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles 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.

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

A third-party supply agreement we assumed in connection with the acquisition of assets from Shell requires that we maintain certain inventories of refined petroleum products. In addition, we maintain product inventory related to our petroleum products management operation. We are required to record these inventories at the lower of cost or market value. Significant decreases in market prices could require us to reduce the recorded value of these inventories, which would in turn reduce our earnings.

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

We depend on connections with refineries and petroleum products pipelines owned and operated by third parties as a significant source of supply for our facilities. Outages at these refineries or reduced 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.*

Since the September 11, 2001 terror 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 pipelines may reduce the amount of cash we generate.*

The FERC regulates the tariff rates for interstate movements on our petroleum products pipelines. Shippers may protest our pipeline tariff filings, and the FERC may investigate new or changed tariff rates and order refunds of amounts collected under rates that were in excess of a just and reasonable level. In addition, shippers may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint.

The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. The FERC's primary ratemaking methodology is price indexing. We use this methodology to establish our rates in approximately 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 for finished goods ("PPI-FG"). If the PPI-FG falls, we could be required to reduce our rates that are based on the FERC's price indexing methodology if they exceed the new maximum allowable rate. In addition, changes in the PPI-FG might not be large enough to fully reflect actual increases in the costs associated with the pipelines subject to indexing.

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

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in BP West Coast Products, LLC v. FERC, which vacated the FERC's application of its Lakehead policy with the result that no income tax allowance can be claimed by pipeline owners that are limited partners. Under that policy, the FERC has allowed a regulated entity organized as a master limited partnership to include in its cost of service an income tax allowance to the extent that its unitholders, or limited partners, were corporations subject to income tax. Because the court's ruling on the FERC's Lakehead policy in BP West Coast appears to focus on the facts and record presented to it in that case, it is not clear what impact, if any, the opinion will have on our indexed rates. On December 2, 2004, the FERC issued a Notice of Inquiry that seeks comments regarding whether BP West Coast applies only to the specific facts of that case, or whether it applies more broadly, and, if the latter, what effect that ruling might have on energy infrastructure investments. It is not clear what action the

FERC will ultimately take in response to BP West Coast, to what extent such action will be challenged and, if so, whether it will withstand further FERC or judicial review. Nevertheless, a shipper might rely on this decision to challenge our indexed rates based on a changed circumstance argument. If the FERC were to disallow our income tax allowance, it may be more difficult to justify our indexed rates on a cost of service basis. However, because of the relatively small percentage of our unitholders that are corporations, which results in our including only a small income tax allowance in our cost of service, we do not believe that a challenge to our indexed rates based solely on the changed circumstance of the elimination of our income tax allowance would be likely to succeed.

We establish rates in approximately two-thirds of our markets using the FERC's market-based ratemaking regulations. These regulations allow us to establish rates based on conditions in individual markets without regard to the index or our cost of service. If successfully challenged, the FERC could take away our ability to establish market-based rates. We would then have to establish rates that would be justified on some other basis such as our cost of service.

Any reduction in the indexed rates, removal of our ability to establish market-based rates, 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 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 our petroleum products pipeline system could result in disruptions or reductions in the volumes we transport and the amount of cash we generate.*

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

Beginning in June 2006, the allowable level of sulfur in on-road and off-road diesel fuel will begin to be lowered to levels that are substantially below current levels. This transition may require us to invest substantial amounts of capital and incur substantial new operating costs that we may not be able to recover through increased revenues. This transition may also require us to transfer low sulfur products to high sulfur products within our system as a result of product contaminations, which in turn could lead to lower product throughputs on our system.

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

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

*Our business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that we store and transport.*

Petroleum products that we store and transport are sold by our customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce our throughput volume, require us to incur additional handling costs or require the expenditure of capital. For instance, different product specifications for different markets impact 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 pursuant to contracts that expire in June 2005.*

Three customers ship all of the ammonia on our pipeline and utilize our six terminals. 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, their failure or inability to pay us or our inability to renegotiate these contracts at terms favorable to 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. 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.

*In connection with its acquisition from Williams of interests in us and our general partner, MMH entered into a New Omnibus Agreement to provide G&A services to us, which increased our G&A expenses and reduced the amount of cash we generate. A change in control of MMH or our general partner could further increase our G&A expenses.*

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 an Omnibus Agreement with MMH. There are limitations on the amount of G&A 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.

The lower cap amount escalates annually 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 escalates annually at the lesser of 2.5% or the percentage increase in the Consumer Price Index. The upper and lower caps are further adjusted for incremental G&A costs associated with acquisitions we consummate.

These limitations on our obligation to reimburse MMH and certain of its affiliates for G&A 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 G&A costs we incur above the lower cap as a result of our becoming liable for the full amount of G&A costs.

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

In connection with MMH's acquisition of interests in us and our general partner, we entered into a new services agreement with MMH and our general partner. The services provided under that agreement include accounting, building administration, human resources, information technology, legal and security, among others. MMH has 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 G&A expenses relating to these services would no longer apply and we may incur increased G&A expenses, which could increase our costs and limit our ability to meet our obligations and pay cash distributions.

*Our general partner and its affiliates may have conflicts with our partnership.*

The directors and officers of our general partner and its affiliates have duties to manage our general partner in a manner that is beneficial to MMH, its sole member. At the same time, our general partner has duties to manage us in a manner that is beneficial to us. Therefore, our general partner's duties to us may conflict with the duties of its officers and directors to MMH.

Such conflicts may include, among others, the following:

- decisions of our general partner regarding the amount and timing of cash expenditures, borrowings and issuances of additional limited partnership units or other securities can affect the amount of incentive distribution payments we make to our general partner;
- under our partnership agreement, we reimburse our general partner for the costs of managing and operating us;
- under our partnership agreement, it is not a breach of our general partner's fiduciary duties for affiliates of our general partner to engage in activities that compete with us. Specifically, MMH, which owns our general partner, is partially owned by an affiliate of the Carlyle/Riverstone Fund, which also owns, through affiliates, an interest in the general partner of Buckeye Partners, L.P. ("Buckeye Partners") and the general partner of SemGroup and may acquire other entities that compete with us. Although we do not have extensive operations in the geographic areas primarily served by Buckeye Partners, we will compete directly with Buckeye Partners, SemGroup and perhaps other entities in which the Carlyle/Riverstone Fund has an interest for acquisition opportunities throughout the United States and potentially will compete with Buckeye Partners, SemGroup and these other entities for new business or extensions of the existing services provided by our operating partnerships, creating actual and potential conflicts of interest between us and affiliates of our general partner. In addition, effective January 2005, it appears that an affiliate of SemGroup has become a significant customer of ours; and
- Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives increasing percentages of our distributions. Distributions to our general partner above the highest target level are at 50%. As the owner of our general partner, MMH indirectly benefits from these distributions. Through ownership of the Class B common units of MMH, which total 6% of the total ownership of MMH, certain executive officers of our general partner also indirectly benefit from these distributions.

In 2004, distributions paid to our general partner totaled $16.7 million. In addition, during 2004, MMH received distributions totaling $28.7 million related to its common and subordinated units. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.9125 per unit, our general partner would receive distributions of approximately $20.8 million in 2005 on its combined 2% general partner interest and incentive distributions. Additionally, MMH would receive $14.9 million on the distribution related to its common and subordinated units. In connection with our October 2004 acquisition of assets from Shell, our partnership agreement was amended to reduce the incentive cash distributions to be paid to our general partner by $5.0 million for 2005. Absent this agreement, the total distribution and combined general partner interest and incentive distribution amounts noted above would be $5.0 million higher.

*The terms of our indemnification settlement agreement require Williams to make payments to us over a period of several years, exposing us to significant credit risk.*

In May 2004, our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release them from certain indemnification obligations to us. We received $35.0 million from Williams on July 1, 2004 and expect to receive the remaining balance in annual installments of $27.5 million, $20.0 million and $35.0 million in July of 2005, 2006 and 2007, respectively. As of December 31, 2004, known liabilities that would have been covered by these indemnifications were $40.8 million. Williams' credit rating is below investment grade. Failure of Williams to perform on its payment obligations under the settlement agreement would reduce our ability to meet our obligations and pay cash distributions.

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

We and our subsidiary, Magellan Pipeline, are subject to restrictions with respect to our debt that may limit our flexibility in structuring or refinancing existing or future debt and prevent us from engaging in certain beneficial transactions. These restrictions include, among other provisions, the maintenance of certain financial ratios, as well as limitations on our ability to incur additional indebtedness, to grant liens, to sell assets or to repay existing debt without penalties. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash.

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

Since February 2004, MMH has sold common units that represented an approximate 19% interest in our capital and profits for tax purposes. We will be considered to have been terminated for federal income tax purposes if the common units sold by MMH, together with all common units sold within a 12-month period, represent a sale or exchange of 50% or more of our capital and profits interests. Our termination for tax purposes would, among other things, result in a significant deferral of the depreciation deductions allowable in computing our taxable income for the year in which the termination occurs.

*Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our exemption from entity-level taxation by states. If the Internal Revenue Service 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.

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

As of December 31, 2004, we had fixed-rate debt of $802.0 million outstanding, excluding the market value of associated interest rate swap agreements. We have converted approximately $350.0 million of this debt to floating-rate debt using interest rate swap agreements. As a result of these agreements, we have significant exposure to changes in short-term interest rates. Rising short-term rates could reduce the amount of cash we generate and adversely affect our ability to meet our financial obligations.

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

We may be exposed to market risk through changes in commodity prices and interest rates. We do not have foreign exchange risks. We have established policies to monitor and control these market risks.

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risk to which we are exposed is interest rate risk. As of December 31, 2004, we had no variable interest debt outstanding; however, because of certain interest rate swap agreements discussed below, we are exposed to $350.0 million of interest rate market risk. If interest rates change by 0.25%, our annual interest expense would change by $0.9 million.

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

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

As of December 31, 2004, we had entered into futures contracts for the acquisition of approximately 1.3 million barrels of petroleum products. The notional value of these agreements, with maturity dates during the first quarter of 2005, was approximately $66.6 million.

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

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2004 and 2003, and the related consolidated statements of income, cash flows and partners' capital for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Oversight Board (United States), the effectiveness of Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 7, 2005, expressed an unqualified opinion theron.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 7, 2005

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

| | Year Ended December 31, 2002 | 2003 | 2004 |
|---|---|---|---|
| Transportation and terminals revenues: | | | |
| Third party | $330,545 | $359,726 | $416,408 |
| Affiliate | 33,195 | 13,122 | — |
| Product sales revenues: | | | |
| Third party | 45,339 | 111,522 | 278,478 |
| Affiliate | 25,188 | 790 | — |
| Affiliate management fee revenues | 210 | — | 488 |
| Total revenues | 434,477 | 485,160 | 695,374 |
| Costs and expenses: | | | |
| Operating | 152,832 | 164,612 | 176,941 |
| Environmental | 16,814 | 14,089 | 43,989 |
| Environmental reimbursements | (14,500) | (11,818) | (41,398) |
| Product purchases | 63,982 | 99,907 | 255,724 |
| Depreciation and amortization | 35,096 | 36,081 | 41,845 |
| Affiliate general and administrative | 43,182 | 56,846 | 54,466 |
| Total costs and expenses | 297,406 | 359,717 | 531,567 |
| Equity earnings | — | — | 1,602 |
| Operating profit | 137,071 | 125,443 | 165,409 |
| Interest expense: | | | |
| Affiliate interest expense | 407 | — | — |
| Other interest expense | 22,500 | 36,597 | 37,893 |
| Interest income | (1,149) | (2,061) | (2,458) |
| Debt prepayment premium | — | — | 12,666 |
| Write-off of unamortized debt placement costs | — | — | 5,002 |
| Debt placement fee amortization | 9,950 | 2,830 | 3,056 |
| Other income | (2,112) | (92) | (953) |
| Income before income taxes | 107,475 | 88,169 | 110,203 |
| Provision for income taxes | 8,322 | — | — |
| Net income | $ 99,153 | $ 88,169 | $110,203 |
| Allocation of net income: | | | |
| Limited partners' interest | $ 80,713 | $ 90,191 | $101,140 |
| General partner's interest | 4,402 | (2,022) | 9,063 |
| Portion applicable to partners' interests | 85,115 | 88,169 | 110,203 |
| Portion applicable to non-partnership interests for the period before April 11, 2002, as it relates to the operations of the petroleum products pipeline system | 14,038 | — | — |
| Net income | $ 99,153 | $ 88,169 | $110,203 |
| Basic net income per limited partner unit | $ 3.68 | $ 3.32 | $ 3.45 |
| Weighted average number of limited partner units outstanding used for basic net income per unit calculation | 21,911 | 27,195 | 29,358 |
| Diluted net income per limited partner unit | $ 3.67 | $ 3.31 | $ 3.44 |
| Weighted average number of limited partner units outstanding used for diluted net income per unit calculation | 21,968 | 27,235 | 29,422 |

See notes to consolidated financial statements.

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

| | December 31, 2003 | December 31, 2004 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 111,357 | $ 29,833 |
| Restricted cash | 8,223 | 5,847 |
| Marketable securities | — | 87,802 |
| Accounts receivable (less allowance for doubtful accounts of $319 and $556 at December 31, 2003 and 2004, respectively) | 19,615 | 35,631 |
| Other accounts receivable | 14,579 | 20,209 |
| Affiliate accounts receivable | 9,324 | 8,637 |
| Inventory | 17,282 | 43,397 |
| Other current assets | 3,941 | 6,385 |
| Total current assets | 184,321 | 237,741 |
| Property, plant and equipment, at cost | 1,371,847 | 1,956,884 |
| Less: accumulated depreciation | 431,298 | 463,266 |
| Net property, plant and equipment | 940,549 | 1,493,618 |
| Equity investments | — | 25,084 |
| Goodwill | 22,057 | 22,007 |
| Other intangibles (less accumulated amortization of $911 and $2,211 at December 31, 2003 and 2004, respectively) | 11,417 | 10,118 |
| Long-term affiliate receivables | 13,472 | 4,599 |
| Long-term receivables | 9,077 | 8,070 |
| Debt placement costs (less accumulated amortization of $2,761 and $4,040 at December 31, 2003 and 2004, respectively) | 10,618 | 10,954 |
| Other noncurrent assets | 3,113 | 5,641 |
| Total assets | $1,194,624 | $1,817,832 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| Current liabilities: | | |
| Accounts payable | $ 21,200 | $ 20,394 |
| Affiliate accounts payable | 257 | 497 |
| Outstanding checks | 6,961 | — |
| Affiliate payroll and benefits | 15,077 | 19,275 |
| Accrued taxes other than income | 14,286 | 16,632 |
| Accrued interest payable | 8,196 | 9,860 |
| Environmental liabilities | 12,243 | 33,160 |
| Deferred revenue | 10,868 | 12,958 |
| Accrued product purchases | 11,585 | 17,313 |
| Accrued product shortages | — | 7,507 |
| Current portion of long-term debt | 900 | 15,100 |
| Other current liabilities | 5,310 | 13,308 |
| Total current liabilities | 106,883 | 166,004 |
| Long-term debt | 569,100 | 789,568 |
| Long-term affiliate payable | 1,509 | 6,578 |
| Long-term affiliate pension and benefits | — | 4,120 |
| Other deferred liabilities | 4,455 | 34,807 |
| Environmental liabilities | 14,528 | 27,646 |
| Commitments and contingencies | | |
| Partners' capital: | | |
| Common unitholders (21,711 units and 28,921 units outstanding at December 31, 2003 and 2004, respectively) | 737,715 | 1,058,913 |
| Subordinated unitholders (5,680 units and 4,260 units outstanding at December 31, 2003 and 2004, respectively) | 135,085 | 101,222 |
| General partner | (373,880) | (369,104) |
| Accumulated other comprehensive loss | (771) | (1,922) |
| Total partners' capital | 498,149 | 789,109 |
| Total liabilities and partners' capital | $1,194,624 | $1,817,832 |

See notes to consolidated financial statements.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2003 | 2004 |
| Operating Activities: | | | |
| Net income | $ 99,153 | $ 88,169 | $ 110,203 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 35,096 | 36,081 | 41,845 |
| Debt placement fee amortization | 9,950 | 2,830 | 3,056 |
| Debt prepayment penalty | — | — | 12,666 |
| Write-off of unamortized debt placement costs | — | — | 5,002 |
| Deferred income taxes | 1,641 | — | — |
| Loss/(Gain) on sale and retirement of assets | (2,088) | 4,563 | 5,164 |
| Gain on interest rate hedge | — | — | (953) |
| Equity earnings | — | — | (1,602) |
| Distributions from equity investment | — | — | 1,550 |
| Changes in operating assets and liabilities (Note 4) | 17,281 | 12,315 | 59,570 |
| Net cash provided by operating activities | 161,033 | 143,958 | 236,501 |
| Investing Activities: | | | |
| Purchases of marketable securities | — | — | (320,205) |
| Sales of marketable securities | — | — | 232,403 |
| Additions to property, plant & equipment | (37,248) | (34,636) | (51,385) |
| Proceeds from sale of assets | 2,706 | 4,034 | 1,794 |
| Equity investments | — | — | (25,032) |
| Acquisitions of businesses | (692,493) | (15,346) | (25,441) |
| Acquisition of assets | — | — | (524,460) |
| Net cash used by investing activities | (727,035) | (45,948) | (712,326) |
| Financing Activities: | | | |
| Distributions paid | (53,373) | (90,527) | (116,943) |
| Borrowings under credit facility | 8,500 | 90,000 | 50,000 |
| Payments on credit facility | (58,000) | (90,000) | (140,000) |
| Borrowings under short-term notes | 700,000 | — | 300,000 |
| Payments on short-term notes | (700,000) | — | (300,000) |
| Borrowings under long-term notes | 480,000 | — | 499,182 |
| Payments on long-term notes | — | — | (178,000) |
| Capital contributions by affiliate | 21,293 | 21,951 | 14,807 |
| Sales of common units to public (less underwriters' commissions and payment of formation and offering costs) | 279,290 | 9,477 | 286,523 |
| Debt placement costs | (19,666) | (2,905) | (8,394) |
| Payment of debt prepayment premium | — | — | (12,666) |
| Payments on affiliate note payable | (29,780) | — | — |
| Net settlement of interest rate hedges | (995) | — | (208) |
| Other | 47 | 200 | — |
| Net cash provided by (used in) financing activities | 627,316 | (61,804) | 394,301 |
| Change in cash and cash equivalents | 61,314 | 36,206 | (81,524) |
| Cash and cash equivalents at beginning of period | 13,837 | 75,151 | 111,357 |
| Cash and cash equivalents at end of period | $ 75,151 | $111,357 | $ 29,833 |
| Supplemental non-cash investing and financing transactions: | | | |
| Contributions by affiliate of long-term debt, deferred income tax liabilities, and other assets and liabilities to Partners' capital | $ 198,117 | $ 17,644 | $ 2,396 |
| Purchase of business through the issuance of class B common units | 304,388 | — | — |

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, 2002** | $ 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 |
| Comprehensive income: | | | | | | |
| Net income | 86,136 | 15,004 | — | 9,063 | — | 110,203 |
| Amortization of loss on cash flow hedge | — | — | — | — | 9 | 9 |
| Net loss on cash flow hedges | — | — | — | — | (1,160) | (1,160) |
| Total comprehensive income | | | | | | 109,052 |
| Conversion of subordinated units to common units (1.4 million units) | 33,024 | (33,024) | — | — | — | — |
| Issuance of common units to public (5.8 million units) | 286,523 | — | — | — | — | 286,523 |
| Affiliate capital contributions | — | — | — | 12,411 | — | 12,411 |
| Distributions | (84,414) | (15,832) | — | (16,697) | — | (116,943) |
| Other | (71) | (11) | — | (1) | — | (83) |
| **Balance, December 31, 2004** | $1,058,913 | $101,222 | $ — | $(369,104) | $(1,922) | $ 789,109 |

See notes to consolidated financial statements.

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

### 1. Organization and Basis of Presentation

Unless indicated otherwise, the terms "our", "we", "us" and similar language refer to Magellan Midstream Partners, L.P., together with our subsidiaries. We were formed in August 2000, as Williams Energy Partners L.P., a Delaware limited partnership, to own, operate and acquire a diversified portfolio of complementary energy assets. The Williams Companies, Inc. ("Williams") formed us by contributing entities under its common control. Williams Energy Partners L.P. was renamed Magellan Midstream Partners, L.P. effective September 1, 2003.

***Change in Ownership of General Partner***

On June 17, 2003, Williams sold its ownership of our common, subordinated and class B common units and all of its membership interests of our general partner, including the incentive distribution rights, to WEG Acquisitions, L.P., a Delaware limited partnership formed by Madison Dearborn Capital Partners IV, L.P. and Carlyle/Riverstone Global Energy and Power Fund II, L.P. WEG Acquisitions, L.P. was renamed Magellan Midstream Holdings, L.P. ("MMH") effective September 1, 2003. The following agreements were executed in conjunction with this sale.

*ATLAS 2000 Agreement*

An affiliate of Williams assigned its rights to and interest in the ATLAS 2000 software system and associated hardware to us.

*Services Agreement*

Prior to June 17, 2003, we 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 our 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 our operations continued to be employees of Williams and its affiliates and, until the employees were transferred to MMH, provided services to us 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 provided specified technical, commercial, information system and administrative services to us for a monthly fee. The Williams' employees assigned to us were transferred to MMH on or before January 1, 2004.

On June 17, 2003, we entered into a new services agreement with MMH pursuant to which MMH agreed to perform specified services, including providing necessary employees to operate our assets after the transition period described above. In return, we agreed to pay MMH for its direct and indirect expenses incurred in providing these services, subject to the limitations on reimbursement of general and administrative ("G&A") 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*

In conjunction with the sale of Williams' interests in us, MMH, Williams and certain of Williams' affiliates entered into a New Omnibus Agreement, to which we are a third-party beneficiary, the terms of which include the items listed below:

- Williams and certain of its affiliates agreed to indemnify us for covered environmental losses related to assets operated by us at the time of our initial public offering date (February 9, 2001). This indemnification was settled with Williams during 2004. See Note 19—Commitments and Contingencies for a discussion of the indemnification settlement.

- Williams and certain of its affiliates agreed to indemnify us 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 us for right-of-way defects or failures associated with the marine terminals at Galena Park and Corpus Christi, Texas and Marrero, Louisiana for 15 years after February 9, 2001.
- MMH will reimburse us for G&A expenses subject to certain limitations. See Note 12—Related Party Transactions for a discussion of the G&A expense limitations and the reimbursement amounts by MMH.

*Other Matters*

- As part of its negotiations with Williams, MMH assumed Williams' obligations to us for $21.9 million of environmental indemnification liabilities.
- Upon the closing of the transaction, MMH, as the sole member of our 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 our general partner as of June 17, 2003. Also, upon the closing of the transaction, the Board of Directors of our general partner and MMH adopted the Third Amendment to Limited Liability Company Agreement of the General Partner, which, among other provisions, requires our 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 our 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 us, (ii) mergers, consolidations, recapitalization or similar transactions involving us, (iii) the sale, exchange or other transfer of assets not in the ordinary course of business of a substantial portion of our assets, (iv) our dissolution or liquidation, (v) material amendments of our partnership agreement and (vi) a material change in the amount of the quarterly distribution paid on our common units or the payment of a material extraordinary distribution.
- Upon closing of the transaction, Williams made certain indemnifications to us, some of which were settled during 2004. See Note 19—Commitments and Contingencies for a discussion of the indemnification settlement.

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. We are required to reimburse MMH for its obligations associated with the post-retirement medical and life benefits for qualifying individuals assigned to our operations.

***Operating Segments***

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

*Petroleum Products Pipeline System*

Our petroleum products pipeline system includes 8,500 miles of pipeline and 43 terminals that provide transportation, storage and distribution services. We acquired approximately 2,000 miles of our pipeline system from Shell Pipeline Company LP and Equilon Enterprises LLC doing business as Shell Oil Products US (collectively "Shell") during 2004. See Note 6—Acquisitions for a discussion of our acquisition of these assets.

Our petroleum products pipeline system covers a 13-state area extending from Texas through the Midwest to Colorado, Illinois, Minnesota and North Dakota. The products transported on our pipeline system are primarily gasoline, diesel fuels, LPGs and aviation fuels. Product originates on the system from direct connections to refineries and interconnects with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airlines and other end-users. We also acquired an ownership interest in Osage Pipeline Company, LLC ("Osage Pipeline") during 2004. This system includes the 135-mile Osage pipeline, which transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to National Cooperative Refining Association's ("NCRA") refinery in McPherson, Kansas and the Frontier refinery in El Dorado, Kansas. The petroleum products management operation we acquired during July 2003 is also included in the petroleum products pipeline system segment.

*Petroleum Products Terminals*

Most of our petroleum products terminals are strategically located along or near third-party pipelines or petroleum refineries. The petroleum products terminals provide a variety of services such as distribution, storage, blending, inventory management and additive injection to a diverse customer group including governmental customers and end-users in the downstream refining, retail, commercial trading, industrial and petrochemical industries. Products stored in and distributed through the petroleum products terminal network include refined petroleum products, blendstocks and heavy oils and feedstocks. The terminal network consists of marine terminals and inland terminals. In October 2004, we acquired certain pipeline and terminalling assets from Shell (see Note 6—Acquisitions). Part of that transaction included a terminal in East Houston, Texas, which is included in our petroleum products terminals segment, increasing the number of marine terminals we operate from five to six. Five of our 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, 2004, we owned 29 inland terminals located primarily in the southeastern United States.

*Ammonia Pipeline System*

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

## 2. Summary of Significant Accounting Policies

***Basis of Presentation***

The consolidated financial statements include the petroleum products pipeline system, the petroleum products terminals and the ammonia pipeline system. We own varying undivided ownership interests in some of our petroleum products terminals. From inception, ownership of these terminals 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, we apply proportionate consolidation for our interests in these assets.

***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 our consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

***Regulatory Reporting***

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

***Cash Equivalents***

Cash and cash equivalents include demand and time deposits and other highly marketable securities with original maturities of three months or less when acquired.

***Marketable Securities***

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

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

***Inventory Valuation***

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

***Trade Receivables and Allowance for Doubtful Accounts***

Trade receivables represent valid claims against non-affiliated customers and are recognized when products are sold or services are rendered. We extend credit terms to certain customers based on historical dealings and to other customers after a review of various credit indicators, including the customers' credit rating. An allowance for doubtful accounts is established for all or any portion of an account where collections are considered to be at risk and reserves are evaluated no less than quarterly to determine their adequacy. Judgments relative to at-risk accounts include the customers' current financial condition, the customers' historical relationship with us and current and projected economic conditions. Trade receivables are written off when the account is deemed uncollectible.

***Property, Plant and Equipment***

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

At the time of our initial public offering in February 2001, we owned the petroleum products terminals and an ammonia pipeline system. On April 11, 2002, we acquired all of the membership interests of Magellan Pipeline Company, L.P. ("Magellan Pipeline"), formerly Williams Pipe Line Company, LLC for approximately $1.0 billion. Because Magellan Pipeline 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 similarly to a pooling of interests. Accordingly, our consolidated financial statements and notes 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 included under the caption "Petroleum Products Pipeline System" in Note 18—Segment Disclosures.

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

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

Expenditures to replace existing assets are capitalized and the replaced assets are removed from the accounts. Expenditures associated with existing assets are capitalized when they improve the productivity or increase the useful life of the asset. Expenditures for maintenance, repairs and minor replacements are charged to operating expense in the period incurred. We capitalize direct costs such as labor and materials as incurred. Indirect project costs, such as overhead, are capitalized based on a percentage of direct labor charged to the respective capital project. We capitalize interest for capital projects with expenditures over $0.5 million that require three months or longer to complete.

***Goodwill and Other Intangible Assets***

We have adopted SFAS No. 142, "Goodwill and Other Intangible Assets." In accordance with this Statement, beginning on January 1, 2002, goodwill, which represents the excess of cost over fair value of assets of businesses acquired, is no longer amortized but is evaluated periodically for impairment. Goodwill at December 31, 2003 and 2004 was $22.1 million and $22.0 million, respectively. The decrease in goodwill is related to a contingent purchase price adjustment associated with a terminal acquired in 2001. The determination of whether goodwill is impaired is based on management's estimate of the fair value of our reporting units as compared to their carrying values. Critical assumptions used in our estimates included: (i) time horizon of 20 years, (ii) revenue growth of 2.5% per year and expense growth of 3.0% per year, except for depreciation expense growth of 1% per year, (iii) weighted-average cost of capital of 9.0% based on assumed cost of debt of 6%, assumed cost of equity of 12.0% and a 50%/50% debt-to-equity ratio, and (iv) 8 times EBITDA multiple for terminal value. We selected October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2002, 2003 or 2004. 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. Amortization of other intangible assets was $0.2 million, $0.8 million and $1.3 million during 2002, 2003 and 2004, respectively.

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

Prior to 2002, 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, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." In accordance with this Statement, we evaluate our long-lived assets of identifiable business activities, other than those held for sale, for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If an impairment were to occur, the amount of the impairment recognized would be calculated as the excess of the carrying amount of the asset over the fair value of the assets, as determined either through reference to similar asset sales or by estimating the fair value using a discounted cash flow approach.

Long-lived assets to be disposed of through sales of assets that meet specific criteria are classified as "held for sale" and are recorded at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the financial statements. We recorded no impairments relative to our long-lived assets during 2002, 2003 or 2004.

***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 amortized over the life of the associated debt instrument using the effective interest method. When debt is retired before its scheduled maturity date, we write-off any remaining placement costs associated with that debt.

### *Capitalization of Interest*

Interest on borrowed funds is capitalized on projects during construction based on the approximate average interest rate of our debt. We capitalize interest on all construction projects requiring three months or longer to complete with total costs exceeding $0.5 million. Capitalized interest for the years ended December 31, 2002, 2003 and 2004 was $0.2 million, $0.1 million, and $0.4 million, respectively.

### *Pension and Post-Retirement Medical and Life Benefit Obligations*

At December 31, 2003, we recognized affiliate pension and post-retirement medical and life obligations associated with Williams' personnel who were assigned to our operations and became employees of MMH on or before January 1, 2004. Beginning January 1, 2004, MMH has maintained defined benefit plans and a defined contribution plan, which provide retirement benefits to substantially all of its employees (See Note 11—Employee Benefit Plans). The pension and post-retirement medical and life liabilities represent the funded status of the present value of benefit obligations net of unrecognized prior service costs/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 us when earned by those employees. We recognized paid-time off liabilities to our general partner of $5.5 million and $6.2 million at December 31, 2003 and 2004, respectively. These balances represent the remaining vested paid-time off benefits of employees who support us. Affiliate liabilities for paid-time off are reflected in the accrued affiliate payroll and benefits balances of the consolidated balance sheets.

### *Derivative Financial Instruments*

We account for hedging activities in accordance with SFAS No. 133, "Accounting for Financial Instruments and Hedging Activities", SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133" and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". These statements establish accounting and reporting standards requiring that derivative instruments be recorded on the balance sheet at fair value as either assets or liabilities.

For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument's intended use and how it is designated. Derivative financial instruments qualifying for hedge accounting treatment can generally be divided into two categories: (1) cash flow hedges and (2) fair value hedges. Cash flow hedges are executed to hedge the variability in cash flows related to a forecasted transaction. Fair value hedges are executed to hedge the value of a recognized asset or liability. At inception of a hedged transaction, we document the relationship between the hedging instrument and the hedged item, the risk management objectives and the methods used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedge item. Furthermore, we assess the creditworthiness of the counterparties to manage against the risk of default. If we determine that a derivative, originally designed as a cash flow or fair value hedge, is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

Derivatives that qualify for and for which we designate as normal purchases and sales are exempted from the fair value accounting requirements of SFAS No.'s 133, 138 and 149 and are accounted for using traditional accrual accounting. As of December 31, 2004, we had commitments under future contracts for product purchases that will be accounted for as normal purchases totaling approximately $66.6 million.

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

***Revenue Recognition***

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

***Buy / Sell Arrangements***

To help manage the supply of inventory and provide specific quantities and grades of products at various locations on our systems, we engage in certain buy / sell arrangements. We are the primary obligor on these transactions and we assume credit risk and risk of ownership for the associated products. Accordingly, under Emerging Issues Task Force ("EITF") Issue No. 99-19, "Recording Revenue Gross as a Principle Versus Net as an Agent" we have included the gross amounts of these transactions in our consolidated statements of income. Amounts associated with these buy / sell arrangements included in product sales revenues and in product purchases on our 2004 consolidated financial statement were $23.1 million. The EITF is considering related matters which may require us to account for these transactions differently in the future. Had these transactions been reported net, our product sales and product purchases in 2004 would have been reduced by $23.1 million.

***G&A Expenses***

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

***Legal Costs***

We are subject to litigation, regulatory proceedings and other legal matters as the result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. To the extent that actual outcomes differ from our estimates or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. When we identify specific litigation that is expected to continue for a period of time and is expected to require substantial expenditures, we identify a range of possible costs, including outside legal costs, to litigate the matter to a conclusion or reach an acceptable settlement. If no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. We revise our contingent litigation and other legal liabilities on at least a quarterly basis.

***Unit-Based Incentive Compensation Awards***

Our general partner has issued incentive awards of phantom units representing limited partner interests in us to certain employees of MMH who support us. These awards are accounted for using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees". Since the grant price of the incentive unit awards made by our general partner is less than the market price of the underlying units, we recognize compensation expense associated with these awards. Compensation cost is recognized over the vesting period of the awards based on either the current market value of our common units at each period end or the market price of the common units at the measurement date, whichever is appropriate. The measurement date for determining compensation costs in our award plan is the first date on which we know both: (1) the number of units that an employee is entitled to receive and (2) the purchase price.

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

***Environmental***

Environmental expenditures that relate to current or future revenues are expensed or capitalized based upon the nature of the expenditures. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments are probable and the costs can be reasonably estimated. Environmental liabilities are recorded independently of any potential claim for recovery. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account currently available facts, existing technologies and presently enacted laws and regulations. Accruals for environmental matters consider our prior remediation experience and include an estimate for costs such as fees paid to contractors and outside engineering, consulting and law firms. Furthermore, costs include compensation and benefit expense of internal employees directly involved in remediation efforts. We maintain selective insurance coverage, which may cover all or portions of certain environmental expenditures. Receivables are recognized in cases where the realization of reimbursements of remediation costs is considered probable.

We have determined that certain costs are covered by the indemnity settlement with Williams (see Note 19—Commitments and Contingencies). We make judgments on what is covered by the settlement and specifically allocate these costs to our general partner. As part of our indemnification settlement with Williams, we are receiving capital contributions from our general partner to cover these costs.

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

***Income Taxes***

We are not a taxable entity for federal and state income tax purposes. Accordingly, for the petroleum products terminals and ammonia pipeline system operations, no recognition has been given to income taxes for financial reporting purposes subsequent to our initial public offering. Prior to our acquisition of Magellan

Pipeline, its results were 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 our acquisition of it in April 2002.

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

***Allocation of Net Income***

Net income is allocated to our general partner and limited partners based on their respective proportional cash distributions declared and paid following the close of each quarter (see Note 22—Distributions). Our general partner is also directly charged with specific costs that it has individually assumed and for which the limited partners are not responsible (see Note 5—Allocation of Net Income).

***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 our general partner consistent with its distribution under the incentive distribution rights declared for each period presented as prescribed by our partnership agreement.

***Comprehensive Income***

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

***Recent Accounting Standards***

In December 2004, the Financial Accounting Standards Board ("FASB") issued a revision to SFAS No. 123, "Share-Based Payment", referred to as "SFAS No. 123R". This Statement establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. This revision requires that all equity-based compensation awards to employees be recognized in the income statement based on their fair values, eliminating the alternative to use APB No. 25's intrinsic value method. The Standard is effective as of the beginning of the first interim period that begins after June 15, 2005. This Statement applies to all awards granted after the required effective date but is not to be applied to awards granted in periods before the required effective date except to the extent that awards from prior periods are modified, repurchased or cancelled after the required effective date. We intend to adopt the Statement on July 1, 2005, using the modified prospective application method. Under the modified prospective method, we will be required to account for all of our equity-based incentive awards granted prior to June 30, 2005 using the fair value method as defined in SFAS No. 123 instead of our current methodology of using the intrinsic value method as defined in APB No. 25. Our existing equity-based awards are stock appreciation rights, as defined in FASB Interpretation ("FIN") No. 28. As such, we recognize compensation expense under APB No. 25/FIN No. 28 in much the same manner as that required under SFAS No. 123. Consequently, the initial adoption and application of SFAS No. 123R will not have a material impact on our financial position, results of operations or cash flows.

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

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

In December 2003, the 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 additional disclosure requirements of this Statement were effective for quarters beginning after December 15, 2003 and for fiscal years ending 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 was effective for financial instruments entered into or modified after May 31, 2003, and otherwise was 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 required 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.

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 amended and clarified financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". The application of this Statement did not have a material impact on our financial position, results of operations or cash flows upon its initial adoption.

In April 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities." The interpretation included a new consolidation model, the variable interest model, which determines control and consolidation based on potential variability in gains and losses of the entity being evaluated for consolidation. FIN No. 46 requires that all entities, with limited exceptions, be evaluated to determine whether or not they are variable interest entities ("VIEs"). All VIEs then are evaluated for consolidation based on their variable interests. The party with the majority of the variability in gains and losses of the VIE is the VIE's primary beneficiary and is required to consolidate the VIE. The interpretation's provisions were effective for enterprises with variable interests in VIE's created after January 31, 2003. The application of FIN No. 46 had no impact on our financial position, results of operations or cash flows.

### 3. Debt and Equity Offerings

In April 2002, we acquired all of the membership interests of Magellan Pipeline from Williams for $1.0 billion. The following debt and equity transactions were completed to help finance that transaction:

- On April 11, 2002, we 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. In December 2003, these class B common units were converted to an equivalent number of common units;
- Also, on April 11, 2002, we borrowed $700.0 million from a group of financial institutions and incurred debt placement costs of $7.1 million. In October 2002, we negotiated an extension of the maturity of this note and incurred additional debt placement costs of $2.1 million;
- In May 2002, we issued 8.0 million common units representing limited partner interests in us 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 us 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 we used to help finance the Magellan Pipeline acquisition. Further, during September 2002, we paid $3.6 million for additional transactions costs associated with this offering;
- In November 2002, we borrowed $420.0 million under the Magellan Pipeline Notes and incurred $9.0 million of associated placement costs. The net proceeds of $411.0 million were used to repay the remaining balance of the $700.0 million short-term note we used to help finance the Magellan Pipeline acquisition; and
- In December 2002, we borrowed $60.0 million under the Magellan Pipeline Notes and incurred $1.5 million of associated placement costs. $58.0 million of the proceeds were used to repay the acquisition sub-facility we had in place at the time with the remainder of the proceeds used for general partnership purposes. At December 31, 2002, Williams' ownership interest in us was 55%, including its 2% general partner interest. Further, we incurred $0.3 million of additional debt placement fees in January 2003 associated with the Magellan Pipeline Notes issued in November and December 2002.

In June 2003, Williams sold its ownership interests in us to MMH. In August 2003, we entered into a new credit facility and the $90.0 million we borrowed under that facility was used to repay the $90.0 million outstanding on the term loan and revolving credit facility in place at that time. We incurred debt placement fees of $2.6 million associated with this transaction.

In December 2003, we issued 0.2 million common units representing limited partner interests in us at a price of $50.00 per unit for total proceeds of $10.0 million. Associated with this offering our general partner contributed $0.2 million to us to maintain its 2% general partner interest. Of the proceeds received, $0.4 million was used to pay underwriting discounts and commissions. Legal, professional and other costs directly associated with this offering were approximately $0.1 million. The remaining cash proceeds of $9.7 million were used for general partnership purposes. Also in December 2003, MMH sold 4.3 million common units representing limited partner interests in us. We did not receive any of the proceeds from MMH's sale of these units. Following this sale and our December 2003 equity issuance of 0.2 million units, MMH's ownership interest in us was reduced from 55% to 39%.

In January 2004, the underwriters exercised their over-allotment option associated with the December 2003 equity offering and MMH sold an additional 0.7 million common units, which reduced their ownership interests in us from 39% to 36%. We did not receive any of the proceeds from MMH's sale of these units.

During May 2004, we executed a refinancing plan to improve our credit profile and increase our financial flexibility by removing all of the secured debt from our capital structure. This refinancing plan included the issuance of $250.0 million of senior notes, establishment of a new revolving credit facility and the offering of 1.0 million common units representing limited partner interests in us. Both the senior notes and common units were issued on May 25, 2004. Associated with this offering, MMH sold approximately 2.4 million common units representing limited partner interests in us. We received none of the proceeds from MMH's sale. MMH's sale of these common units, combined with our equity offering, reduced MMH's ownership interest in us from 36% to 27%.

Total proceeds from our 1.0 million common unit equity offering at a price of $47.60 per unit were $47.6 million. Associated with this offering, our general partner contributed $1.0 million to us to maintain its 2% general partner interest. Of the proceeds received, $2.0 million was used to pay underwriting discounts and commissions. Legal, professional and other costs associated with the equity offering were approximately $0.2 million. Total proceeds from the note issuance were $249.5 million. Of the proceeds received, $1.8 million was used to pay underwriting discounts and commissions and $0.8 million was used to pay legal, professional and other fees. We used the net proceeds from the May 2004 offerings of $293.3 million as follows:

- repaid all of the outstanding $178.0 million principal amount of Series A senior notes (see Note 15—Debt for a description of these notes) issued by Magellan Pipeline;
- paid $12.7 million of prepayment premiums associated with the early repayment of the Magellan Pipeline Series A senior notes;
- repaid the $90.0 million outstanding principal balance of our then outstanding term loan;
- paid $1.9 million to Magellan Pipeline's Series B noteholders (see Note 15—Debt for a description of these notes) to release the collateral held by them and $0.8 million of associated legal costs;
- paid $0.9 million of legal and professional fees associated with establishing a new unsecured revolving credit facility (see Note 15—Debt for a description of this facility); and
- partially replenished the cash used to fund acquisitions completed in 2003 and early 2004.

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

On October 1, 2004, we completed an acquisition of assets from Shell (see Note 6—Acquisitions). The debt and equity offerings discussed below were completed as part of the financing requirements associated with that acquisition:

- During August 2004, in anticipation of the acquisition of assets from Shell, we issued and sold 1.8 million common units representing limited partner interests in us. Total proceeds from the sale, at a price of $49.77 per unit, were $89.6 million. Associated with this offering, our general partner made a $1.8 million contribution to us to maintain its 2% general partner interest. Net proceeds after underwriter discounts of $3.8 million and offering expenses of approximately $0.5 million were $87.1 million. The underwriters exercised their over-allotment option associated with this equity offering and sold an additional 0.3 million units. These over-allotment units were sold by MMH and we did not receive any of the cash proceeds from that sale. As a result of this equity offering and sale of over-allotment units, MMH's ownership interest in us, including its 2% ownership interest through our general partner, decreased from 27% to 25%;
- On October 1, 2004, we borrowed $300.0 million under a short-term acquisition facility and $50.0 million under our revolving credit facility to help finance this acquisition. We incurred debt issuance costs of $0.1 million associated with the $300.0 million short-term acquisition facility;
- On October 4, 2004, we issued and sold 2.6 million common units representing limited partner interests in us. The units were sold at a price of $54.50 for total proceeds of $141.7 million. Associated with this offering, our general partner contributed $2.9 million to us to maintain its 2% general partner interest. Of the proceeds received, $6.0 million was used to pay underwriting discounts and commissions. Legal, professional and other costs associated with the equity offering were approximately $0.3 million. We used the net proceeds of $138.3 million to repay a portion of the amounts borrowed under the short-term acquisition facility. The underwriters exercised their over-allotment option associated with the October 2004 offering and on November 1, 2004, we issued and sold an additional 0.4 million common units. Total proceeds from this sale were $21.3 million, of which we paid $0.9 million for underwriting discounts and commissions. Our general partner made an additional $0.4 million contribution to maintain its 2% general partner interest. The net proceeds of $20.8 million from the over-allotment sale were used to replace cash we used to pay for other investments. These equity issuances further reduced MMH's ownership interest in us from 25% to 23%; and
- On October 15, 2004, we issued $250.0 million of senior notes. The notes were issued for the discounted price of 99.9%, or $249.7 million. The net proceeds from this debt issuance, after underwriter discounts of $1.8 million and debt issuance fees of $0.3 million, were $247.6 million. We used these net proceeds to: (i) repay the remaining $161.7 million outstanding under the acquisition facility (the original $300.0 million borrowed less $138.3 million partial repayment from the October 4, 2004 equity offering discussed above) plus accrued interest costs of $0.2 million, and (ii) repay the $50.0 million amount previously borrowed under the revolver plus accrued interest costs of $0.1 million. The remaining proceeds of $35.6 million from this debt offering were used to replenish cash used in the acquisition of assets from Shell.

## 4. Consolidated Statements of Cash Flows

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2003 | 2004 |
| Accounts receivable and other accounts receivable | $ (5,007) | $ (6,096) | $(21,646) |
| Affiliate accounts receivable | (8,876) | 3,040 | 687 |
| Inventory | 5,361 | (6,812) | 3,864 |
| Accounts payable | 4,332 | 3,938 | (380) |
| Affiliate accounts payable | 8,247 | (9,977) | 158 |
| Affiliate income taxes payable | 487 | — | — |
| Affiliate payroll and benefits | 1,702 | 8,260 | 4,532 |
| Accrued taxes other than income | 3,749 | 589 | (1,074) |
| Accrued interest payable | 3,788 | 4,131 | 1,664 |
| Accrued product purchases | 214 | 8,660 | 5,728 |
| Accrued product shortages | — | — | 7,507 |
| Restricted cash | (4,942) | (3,281) | 2,376 |
| Cash collateral | — | — | 14,000 |
| Current and noncurrent environmental liabilities | 7,542 | 4,485 | 27,894 |
| Other current and noncurrent assets and liabilities | 684 | 5,378 | 14,260 |
| Total | $17,281 | $12,315 | $ 59,570 |

## 5. Allocation of Net Income

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

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| Allocation of net income to general partner: | | | |
| Net income applicable to the partners' interests | $85,115 | $ 88,169 | $110,203 |
| Direct charges to general partner: | | | |
| Write-off of property, plant and equipment | — | 1,788 | — |
| G&A portion of paid-time off accrual | — | 2,108 | — |
| Transition charges | — | 1,233 | 823 |
| Charges in excess of the G&A expense cap charged against income | — | 5,974 | 6,397 |
| Environmental charges previously indemnified by Williams | — | — | 1,351 |
| Total direct charges to general partner | — | 11,103 | 8,571 |
| Income before direct charges to general partner | 85,115 | 99,272 | 118,774 |
| General partner's share of income | 5.172% | 9.147% | 14.846% |
| General partner's allocated share of net income before direct charges | 4,402 | 9,081 | 17,634 |
| Direct charges to general partner | — | (11,103) | (8,571) |
| Net income (loss) allocated to general partner | $ 4,402 | $ (2,022) | $ 9,063 |
| Net income applicable to the partners' interests | $85,115 | $ 88,169 | $110,203 |
| Less: net income (loss) allocated to general partner | 4,402 | (2,022) | 9,063 |
| Net income allocated to limited partners | $80,713 | $ 90,191 | $101,140 |

The write-off of property, plant and equipment relates to Magellan Pipeline's asset balances prior to our acquisition of it; as a result, these write-offs were charged directly against our general partner's allocation of net income. The G&A portion of paid-time-off expense accrual and the charges in excess of the G&A expense cap represent G&A expenses charged against our income during the periods presented that were required to be reimbursed to us by our general partner under the terms of the New Omnibus Agreement. The transition charges represent our costs for transitioning from Williams to a stand-alone enterprise in excess of the amount we were contractually required to pay. Consequently, all of these amounts have been charged directly against our general partner's allocation of net income. We record the reimbursements by our general partner as capital contributions. During 2004, we and our general partner entered into an agreement with Williams to settle Williams' indemnification obligations to us (see Note 19—Commitments and Contingencies). Following this settlement, the expenses associated with these previously indemnified costs are charged directly to the general partner. We believe we will collect the full amount of the indemnification settlement from Williams and accordingly will continue to allocate amounts associated with previously indemnified costs to our general partner.

## 6. Acquisitions

The following acquisition has been accounted for as an acquisition of a business:

### *Petroleum Products Terminals*

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

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

***Pro Forma Information (unaudited)***

The following summarized pro forma consolidated income statement information for the years ended December 31, 2003 and 2004 assumes that the January 2004 petroleum product terminals acquisition discussed above had occurred as of January 1, 2003. We have prepared these pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if we had completed these acquisitions as of the periods shown below or the results that will be attained in the future. The amounts presented below are in thousands, except per unit amounts:

| | Year Ended December 31, 2003 | | | Year Ended December 31, 2004 | | |
|---|---|---|---|---|---|---|
| | As Reported | Pro Forma Adjustments | Pro Forma | As Reported | Pro Forma Adjustments | Pro Forma |
| Revenues | $485,160 | $ 6,696 | $491,856 | $695,374 | $ 525 | $695,899 |
| Net income | $ 88,169 | $ 1,690 | $ 89,859 | $110,203 | $ 118 | $110,321 |
| Basic net income per limited partner unit | $ 3.32 | $ 0.05 | $ 3.37 | $ 3.45 | $ — | $ 3.45 |
| Diluted net income per limited partner unit | $ 3.31 | $ 0.05 | $ 3.36 | $ 3.44 | $ — | $ 3.44 |
| Weighted average number of limited partner units used for basic net income per unit calculation | 27,195 | 27,195 | 27,195 | 29,358 | 29,358 | 29,358 |
| Weighted average number of limited partner units used for diluted net income per unit calculation | 27,235 | 27,235 | 27,235 | 29,422 | 29,422 | 29,422 |

Significant pro forma adjustments include: revenues and expenses for the period prior to our acquisitions and incremental G&A expenses.

The following acquisitions have been accounted for as acquisitions of assets:

***Petroleum Products Management Operation***

In July 2003, we 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 and are reported as 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 from the acquisition date.

***Pipeline Asset Acquisition***

On October 1, 2004, we acquired more than 2,000 miles of petroleum products pipeline system assets from Shell for approximately $487.4 million. In addition to the purchase price, we paid approximately $30.0 million for inventory related to a third-party supply agreement under which we received $14.0 million cash collateral, assumed approximately $29.6 million of existing liabilities and incurred approximately $6.3 million for transaction costs.

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

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

*Assumed Liabilities*

In conjunction with the acquisition, we agreed to assume from Shell the third-party supply agreement mentioned above, the terms of which we believe will be at below-market rates on average over the life of the contract. We recognized the fair value of this supply agreement at closing, which resulted in an increase of $15.7 million in the recorded book value of the assets purchased from Shell, with an offsetting deferred liability.

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

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

We recorded approximately $1.9 million of environmental liabilities upon the closing of the acquisition related to our estimates for remediation sites that Shell did not consider to be currently active. We are in the process of evaluating each of these sites and will adjust the environmental liabilities associated with these sites and our purchase price once the site assessments have been completed.

Upon closing of this acquisition, we were assessed a use tax liability of $1.1 million by the State of Oklahoma.

*Allocation of Purchase Price*

Our allocation of the purchase price of the assets acquired and liabilities assumed from Shell is as follows (in millions):

| | |
|---|---|
| Purchase price: | |
| Cash paid for pipeline systems | $487.4 |
| Cash paid for inventory | 30.0 |
| Capitalized portion of transaction costs | 6.3 |
| Liabilities assumed: | |
| Fair value of third-party supply agreement | 15.7 |
| Consent decree | 8.6 |
| Property tax liability | 2.3 |
| Environmental | 1.9 |
| Use tax liability | 1.1 |
| Total liabilities assumed | 29.6 |
| Total purchase price | $553.3 |
| Allocation of purchase price: | |
| Property, plant and equipment | $521.8 |
| Inventory | 30.0 |
| Prepaid assets | 1.5 |
| Total purchase price | $553.3 |

We have recorded the cost of the assets, assumed liabilities, a portion of the transaction costs and the fair value adjustment of the assumed supply agreement as property, plant and equipment. The purchase price could change based on future events that are different from those assumed at the time of the acquisition.

*Financing*

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

*Description of the Assets*

The acquisition primarily included four refined products pipeline systems, comprising approximately 2,000 miles of pipelines that have been incorporated into our existing pipeline system. A brief description of each of these pipeline segments follows:

- a segment that extends from East Houston to Frost, Texas, which is approximately 50 miles south of Dallas, Texas. From Frost the segment has a branch that extends west to Odessa and El Paso, Texas and a branch that extends to a connection with our existing pipeline system in Duncan, Oklahoma. We connected our existing Galena Park, Texas marine terminal to the East Houston facility through a pipeline connection during February 2005;
- a segment that extends from Hearne, Texas to Dallas, Texas, with an idle portion that extends to Ft. Worth, Texas. The pipeline delivers product to our existing inland terminal in Dallas, Texas;
- a segment that extends from El Dorado, Kansas to Aurora, Colorado with an extension into the Denver International Airport; and
- a pipeline that originates at Glenpool, Oklahoma and extends to Cushing, Oklahoma and then on to El Dorado, Kansas.

*Other Assets*

In addition to the four refined products pipeline systems described above, we also acquired a terminal in Oklahoma City, Oklahoma. Because we already owned a terminal in Oklahoma City, the Federal Trade Commission is requiring us to sell the terminal in Oklahoma City acquired from Shell. We believe this terminal is not material to the operation of the assets acquired from Shell. In connection with the Federal Trade Commission-imposed sale of this terminal, we were required to enter into an agreement with Shell whereby we agreed to pay Shell to operate the terminal until its sale.

*Agreements with Shell*

In connection with our acquisition of these refined petroleum products pipeline systems, we entered into three-year terminalling and transportation agreements and a five-year storage lease agreement with Shell for a combined minimum revenue commitment averaging approximately $28.1 million per year through September 30, 2007 and approximately $750,000 per year thereafter through September 30, 2009.

## 7. Inventory

Inventories at December 31, 2003 and 2004 were as follows (in thousands):

| | December 31, | |
|---|---|---|
| | 2003 | 2004 |
| Refined petroleum products | $ 3,435 | $28,694 |
| Natural gas liquids | 12,362 | 12,682 |
| Additives | 977 | 1,632 |
| Other | 508 | 389 |
| Total inventories | $17,282 | $43,397 |

The significant increase in refined petroleum products inventories is primarily due to the inventory requirements associated with a supply agreement we assumed as part of our asset acquisition from Shell in October 2004 (see Note 6—Acquisitions).

## 8. Property, Plant and Equipment

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

| | December 31, | | Estimated Depreciable Lives |
|---|---|---|---|
| | 2003 | 2004 | |
| Construction work-in-progress | $ 14,657 | $ 18,162 | |
| Land and rights-of-way | 30,172 | 47,185 | |
| Carrier property | 893,660 | 1,294,500 | 24 – 50 years |
| Buildings | 8,306 | 10,892 | 20 – 53 years |
| Storage tanks | 178,984 | 246,164 | 20 – 40 years |
| Pipeline and station equipment | 72,096 | 134,954 | 4 – 59 years |
| Processing equipment | 139,724 | 163,229 | 3 – 53 years |
| Other | 34,248 | 41,798 | 3 – 48 years |
| Total | $1,371,847 | $1,956,884 | |

Carrier property is defined as pipeline assets regulated by the FERC. Other includes capitalized interest at December 31, 2003 and 2004 of $19.3 million and $19.2 million, respectively. Depreciation expense for the years ended December 31, 2002, 2003 and 2004 was $34.9 million, $35.3 million and $40.5 million, respectively.

## 9. Equity Investments

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

We use the equity method of accounting for this investment. Summarized financial information for Osage Pipeline from the acquisition date (March 2, 2004) through December 31, 2004 is presented below (in thousands):

| | |
|---|---|
| Revenues | $9,814 |
| Net income | $4,310 |

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

| | |
|---|---|
| Current assets | $3,278 |
| Noncurrent assets | $5,006 |
| Current liabilities | $ 351 |
| Members' equity | $7,933 |

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

| | |
|---|---|
| Initial investment | $25,032 |
| Earnings in equity investment: | |
| Proportionate share of earnings | 2,155 |
| Amortization of excess investment | (553) |
| Net earnings in equity investment | 1,602 |
| Cash distributions | (1,550) |
| Equity investment, December 31, 2004 | $25,084 |

Our investment in Osage Pipeline included an excess net investment amount of $21.7 million. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment.

## 10. Major Customers and Concentration of Credit Risk

The percentage of revenues derived by customers that accounted for 10% or more of our total revenues is provided in the table below. Customer A is a customer of both our petroleum products pipeline and petroleum products terminals segments. Customer B is a customer of our petroleum products pipeline segment.

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| Customer A | 4% | 27% | 19% |
| Customer B | 0% | 0% | 13% |
| Total | 4% | 27% | 32% |

We transport petroleum products for refiners and marketers in the petroleum industry. The major concentration of our petroleum products pipeline system's revenues is derived from activities conducted in the central United States. Sales to our customers are generally unsecured and the financial condition and creditworthiness of customers are periodically evaluated. We have the ability with many of our pipeline and terminals contracts to sell stored customer products to recover unpaid receivable balances, if necessary. Issues impacting the petroleum refining and marketing and ammonia industries could impact our overall exposure to credit risk.

To conduct our operations, our affiliate, MMH employs approximately 955 employees. MMH considers its employee relations to be good. The number of individuals employed by MMH increased by approximately 87 employees as a result of our acquisition of certain assets from Shell (see Note 6—Acquisitions). Employees at our Odessa and Tye, Texas facilities were formerly represented by a labor union, but on January 7, 2005 these employees voted to decertify the union.

The petroleum products pipeline system's labor force of 506 employees is concentrated in the central United States. At December 31, 2004, approximately 42% of these employees were represented by the Paper, Allied-Industrial, Chemical & Energy Workers International Union and covered by collective bargaining agreements that extend through January 31, 2006. The petroleum products terminals operation's labor force of 209 people is concentrated in the southeastern and Gulf Coast regions of the United States. At December 31, 2004, none of the terminal operations employees were represented by labor unions. However, on January 5, 2005 the Teamsters Union filed a petition with the National Labor Relations Board seeking recognition as the exclusive collective bargaining representative for 25 employees at our New Haven, Connecticut terminal. A recognition election was held on February 11, 2005, and the employees voted to not be represented by the Teamsters Union. Our ammonia pipeline is conducted through a third-party contractor and we have no employees specifically assigned to those operations.

## 11. Employee Benefit Plans

Even though Williams sold its interest in us to MMH on June 17, 2003, employees dedicated to or otherwise supporting our operations remained employees of Williams through December 31, 2003 and many participated in Williams sponsored employee benefit plans. For the period from June 18, 2003 through December 31, 2003, Williams charged us for the services of the employees in accordance with the TSA as defined under *Services Agreement* in Note 1—Organization and Basis of 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 us related to the dedicated employees' participation in the plans totaled $2.9 million for the year ended December 31, 2002 and $1.8 million for the period from January 1, 2003 to June 17, 2003. Expense charges from Williams to us under the TSA related to the period from June 18, 2003 through December 31, 2003 were not specifically identifiable to the dedicated employees' participation in the plan.

Employees dedicated to or otherwise supporting our operations also participated in a Williams defined-contribution plan. The plan provided for matching contributions within specified limits. Affiliate charges from Williams to us related to the dedicated employees' participation in the plan totaled $2.3 million for the year ended December 31, 2002 and $0.7 million for the period from January 1, 2003 to June 17, 2003. Expense charges from Williams to us 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.

On January 1, 2004, MMH assumed sponsorship of the Union Pension Plan for certain hourly employees. Additionally, MMH began sponsorship of a pension plan for certain non-union employees and a post-retirement benefit plan for selected employees effective January 1, 2004. The annual measurement date for our plans is December 31; however, we used a January 1, 2004 measurement date for these plans for the measurement of our initial liability. The following table presents the changes in benefit obligations and plan assets for pension benefits and other post-retirement benefits for the year ended December 31, 2004. The 2003 data presented in the table represents the initial benefit obligation and related plan assets which, on December 31, 2003, we had a commitment to assume from Williams. The table also presents a reconciliation of the funded status of these benefits to the amount recorded in the consolidated balance sheet at December 31, 2004 (in thousands):

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2003 | 2004 | 2003 | 2004 |
| Change in benefit obligation: | | | | |
| Benefit obligation at beginning of year | | $ 26,294 | | $ 18,266 |
| Service cost | | 3,647 | | 324 |
| Interest cost | | 1,707 | | 682 |
| Plan participants' contributions | | — | | 10 |
| Actuarial loss | | 4,044 | | 1,106 |
| Other * | | — | | (7,357) |
| Benefits paid | | (1,795) | | (32) |
| Benefit obligation at end of year | $26,294 | $ 33,897 | $ 18,266 | 12,999 |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of year | | 19,453 | | — |
| Employer contributions | | 3,056 | | 22 |
| Plan participants' contributions | | — | | 10 |
| Actual return on plan assets | | 1,432 | | — |
| Benefits paid | | (1,795) | | (32) |
| Fair value of plan assets at end of year | 19,453 | 22,146 | — | — |
| Funded status | (6,841) | (11,751) | (18,266) | (12,999) |
| Unrecognized net actuarial loss | — | 4,249 | — | 1,106 |
| Unrecognized prior service cost | 6,841 | 6,164 | 18,266 | 9,111 |
| Accrued benefit cost | $ — | $ (1,338) | $ — | $ (2,782) |
| Accumulated benefit obligation | $18,252 | $ 23,441 | N/A | N/A |

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

The amounts included in the pension benefits in the above table combine our Union Pension Plan with our non-union pension plan. At December 31, 2004, the Union Pension Plan had an accumulated benefit obligation of $21.9 million, which exceeded the fair value of plan assets of $20.2 million.

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

| | Pension Benefits | Other Post-retirement Benefits |
|---|---|---|
| Components of net periodic pension and post-retirement benefit expense: | | |
| Service cost | $ 3,647 | $ 324 |
| Interest cost | 1,707 | 682 |
| Expected return on plan assets | (1,637) | — |
| Amortization of prior service cost | 677 | 1,798 |
| Net periodic pension expense | $ 4,394 | $2,804 |

The weighted-average assumptions utilized to determine benefit obligations as of January 1, 2004 and December 31, 2004 are as follows:

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2003 | 2004 | 2003 | 2004 |
| Discount rate | 6.25% | 5.75% | 6.25% | 5.75% |
| Rate of compensation increase | 5.00% | 5.00% | N/A | N/A |

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

| | Pension Benefits | Other Post-retirement Benefits |
|---|---|---|
| Discount rate | 6.25% | 6.25% |
| Expected return on plan assets | 8.50% | N/A |
| Rate of compensation increase | 5.00% | N/A |

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

For benefits incurred by participants prior to age 65, the annual assumed rate of increase in the health care cost trend rate for 2005 is 7.1% and systematically decreases to 5% by 2008. The annual assumed rate of increase in the health care cost trend rate for post-65 benefits for 2005 is 10% and systematically decreases to 5% by 2015. The health care cost trend rate assumption has a significant effect on the amounts reported. A 1.0% change in assumed health care cost trend rates would have the following effect (in thousands):

| | Point Increase | Point Decrease |
|---|---|---|
| Change in total of service and interest cost components | $ 208 | $ 165 |
| Change in post-retirement benefit obligation | 2,519 | 2,003 |

The expected long-term rate of return on plan assets was determined by combining a review of historical returns of portfolios with assets similar to our current portfolio, projected returns and target weightings of each asset classification. Our investment objectives for the assets within the pension plans are to obtain a balance between long-term growth of capital and generation of income to meet withdrawal requirements, while avoiding excessive risk. Defined diversification goals are set in order to reduce the risk of wide swings in the market value from year-to-year, or of incurring large losses that may result from concentrated positions. Our tolerance for risk is analyzed based on the impact on the predictability of contribution requirements, probability of under funding, risk-adjusted returns and investment return volatility. Funds are invested through the use of multiple investment managers. Our target allocation percentages and the actual weighted-average asset allocation at December 31, 2004 are as follows:

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

Benefits expected to be paid through December 31, 2014 are as follows (in thousands):

| | Pension Benefits | Other Post-retirement Benefits |
|---|---|---|
| 2005 | $ 825 | $ 60 |
| 2006 | 833 | 159 |
| 2007 | 835 | 261 |
| 2008 | 895 | 371 |
| 2009 | 928 | 491 |
| 2010 through 2014 | 6,417 | 4,026 |

Contributions estimated to be paid in 2005 are $4.6 million and $0.1 million for the pension and other post-retirement benefit plans, respectively. We maintain a defined-contribution plan and incurred costs of $3.1 million related to this plan during 2004.

## 12. Related Party Transactions

Through June 17, 2003, affiliate revenues represented revenues from Williams and its affiliates. Affiliate revenues during 2002 and 2003 primarily included pipeline and terminal storage revenues, ancillary service revenues for our marine facilities, fee income related to petroleum products asset management activities and certain software licensing fees. Sales to affiliates of Williams were at prices consistent with those charged to non-affiliated entities. Revenues from affiliates of Williams are summarized in the table below (in millions):

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| Revenues from affiliates of Williams | $ 58.6 | $ 13.9 | $ — |
| Total revenues | $434.5 | $485.2 | $695.4 |
| Revenues from affiliates of Williams as a percent of total revenue | 13% | 3% | 0% |

In March 2004 we acquired a 50% ownership interest in Osage Pipeline. We operate the Osage pipeline and receive a fee for these services. During 2004 we received $0.5 million from Osage Pipeline for operating fees, which we reported as affiliate revenues. We also received $0.3 million from Osage for fees to transition accounting, billing and other administrative functions to us. These fees were recorded as other income, which is netted into operating expense in our results of operations.

MMH, which owns our general partner, is partially owned by an affiliate of the Carlyle/Riverstone Global Energy and Power Fund II, L.P., (the "Carlyle/Riverstone Fund"). Two of the members of our general partner's eight member board of directors are nominees of the Carlyle/Riverstone Fund. On January 25, 2005, the Carlyle/Riverstone Fund, through affiliates, acquired an interest in the general partner of SemGroup, L.P. ("SemGroup") and limited partner interests in SemGroup. The Carlyle/Riverstone Fund's total combined general and limited partner interest in SemGroup is approximately 30%. Three of the members of SemGroup's general partner's nine-member board of directors are nominees of the Carlyle/Riverstone Fund. We, through our affiliates, are parties to a number of transactions with SemGroup and its affiliates. These transactions include leasing storage tanks to and from SemGroup, buying and selling petroleum products from and to SemGroup and transporting petroleum products for SemGroup. The board of directors of our general partner has adopted a Board of Directors Conflict of Interest Policy and Procedures. In compliance with this policy, the Carlyle/Riverstone Fund has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to SemGroup. As part of these procedures, the Carlyle/Riverstone Fund has agreed that no individual representing them will serve at the same time on our general partner's board of directors and on SemGroup's general partner's board of directors.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives increasing percentages of our distributions. Distributions to our general partner above the highest target level are at 50%. As the owner of our general partner, MMH indirectly benefits from these distributions. Through ownership of the Class B common units of MMH, which total 6% of the total ownership of MMH, certain executive officers of our general partner also indirectly benefit from these distributions. In 2004, distributions paid to our general partner totaled \$16.7 million. In addition, during 2004, MMH received distributions totaling \$28.7 million related to its common and subordinated units. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of \$0.9125 per unit, our general partner would receive in 2005 distributions of approximately \$20.8 million in 2005 on its combined 2% general partner interest and incentive distributions. Additionally, MMH would receive \$14.9 million on the distribution related to its common and subordinated units. In connection with our October 2004 acquisition of assets from Shell, our partnership agreement was amended to reduce the incentive cash distributions to be paid to our general partner by \$5.0 million for 2005. Absent this agreement, the total distribution and combined general partner interest and incentive distribution amounts noted above in 2005 would be \$5.0 million higher.

Costs and expenses related to activities between Williams and its affiliates and us after June 17, 2003, have been accounted for as unaffiliated third-party transactions. Transactions after June 17, 2003 between us and MMH and its affiliates have been accounted for as affiliate transactions. 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, | | |
|---|---|---|---|
| | 2002 | 2003 | 2004 |
| Affiliates of Williams—allocated G&A expenses | \$ 43,182 | \$23,880 | \$ — |
| Affiliates of Williams—allocated operating expenses | 156,464 | 68,079 | — |
| Affiliates of Williams—product purchases | 22,268 | 472 | — |
| MMH—allocated operating expenses | — | 98,804 | 58,777 |
| MMH—allocated G&A expenses | — | 32,966 | 54,466 |

In 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated both direct and indirect G&A expenses to our general partner. Direct expenses allocated by Williams were primarily salaries and benefits of employees and officers associated with our businesses. Indirect expenses included legal, accounting, treasury, engineering, information technology and other corporate services. Williams allocated these expenses to our general partner based on an agreed-upon expense limitation. On June 17, 2003, Williams' ownership in us was sold to MMH. As a result, we entered into a new services agreement with MMH pursuant to which MMH agreed to perform specified services required for our operations. Consequently, our G&A expenses are now provided by MMH and we now reimburse MMH for those costs, subject to the limitations as defined in the New Omnibus Agreement (see *Reimbursement of G&A Expense* below). The additional G&A costs incurred but not reimbursed by Williams totaled $19.7 million in 2002 and $5.2 million for the period January 1, 2003 through June 17, 2003. The G&A costs allocated from Williams for the periods discussed above included a number of costs that were not specific to our businesses and therefore cannot be used as an estimate of our G&A costs during those periods. The additional G&A costs incurred but not reimbursed by MMH are discussed below under *Reimbursement of G&A Expense.* Additionally, in 2002 and for the period January 1, 2003 through June 17, 2003, Williams allocated operating expenses to our general partner. Expenses included all costs directly associated with our operations. From June 17, 2003 through December 31, 2003 operating expenses were allocated to our general partner from MMH.

Williams agreed to reimburse us for maintenance capital expenditures incurred in 2002 in excess of $4.9 million related to the assets contributed to us at the time of our initial public offering. During 2002, we recorded reimbursements from Williams associated with these assets of $11.0 million.

Williams and certain of its affiliates had indemnified us against certain environmental costs. The environmental indemnifications we had with Williams were settled during 2004. See Note 19—Commitments and Contingencies for information relative to our settlement of these indemnifications with Williams. Receivables from Williams or its affiliates associated with those environmental costs were $7.8 million at December 31, 2003, and were included with accounts receivable amounts presented in the consolidated balance sheets. In addition, MMH has indemnified us against certain environmental costs. Receivables from MMH were $19.0 million and $11.5 million at December 31, 2003 and 2004, respectively, and are included with the affiliate accounts receivable in the consolidated balance sheets.

*Reimbursement of G&A Expense*

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

- The reimbursement obligation is subject to a lower cap amount, which is calculated as follows:
  - › For the period June 18, 2003 through December 31, 2003, MMH reimbursed us $6.0 million for G&A costs in excess of a lower cap amount;
  - › For each succeeding fiscal year, the lower cap is adjusted by the greater of: (i) 7%, or (ii) the percentage increase in the Consumer Price Index—All Urban Consumers, U.S. City Average, Not Seasonally Adjusted. However, the reimbursement amount will also be adjusted for acquisitions, construction projects, capital improvements, replacements or expansions that we complete that are expected to increase our G&A costs. During 2004, MMH reimbursed us $6.4 million for G&A costs in excess of the lower cap amount of $41.8 million;
  - › Additionally, the expense reimbursement limitation excludes: (i) expenses associated with equity-based incentive compensation plans and (ii) implementation costs associated with changing our name and expenses and capital expenditures associated with transitioning the assets, operations and employees from Williams to MMH or us.

- The reimbursement limitation is further subject to an upper cap amount. MMH is not required to reimburse us for any G&A expenses that exceed this upper cap amount. The upper cap is calculated as follows:
  - › For the period of June 18, 2003 through December 31, 2003, the upper cap was approximately $26.6 million, which represents an annual upper cap amount of $49.3 million pro-rated for the period from June 18, 2003 through December 31, 2003;
  - › For each succeeding fiscal year, the upper cap is increased annually by the lesser of: (i) 2.5%, or (ii) the percentage increase in the Consumer Price Index—All Urban Consumers, U.S. City Average, Not Seasonally Adjusted. The upper cap will also be adjusted for acquisitions, construction projects and capital improvements, replacements or expansions that we complete that are expected to increase our G&A costs. For 2004, the upper cap was adjusted to $51.5 million.

## 13. Income Taxes

We do not pay income taxes due to our legal structure. However, earnings of Magellan Pipeline prior to our acquisition of it in April 2002, were subject to income taxes. The provision for income taxes for the year ended December 31, 2002, is as follows (in thousands):

| | 2002 |
|---|---|
| Current: | |
| Federal | $6,313 |
| State | 874 |
| Deferred: | |
| Federal | 987 |
| State | 148 |
| | $8,322 |

A reconciliation from the provision for income taxes at the U.S. federal statutory rate to the effective tax rate for the provision for income taxes for the year ended December 31, 2002, is as follows (in thousands):

| | |
|---|---|
| Income taxes at statutory rate | $ 37,616 |
| Less: income taxes at statutory rate on income applicable to partners' interest | (29,790) |
| Increase resulting from: | |
| State taxes, net of federal income tax benefit | 496 |
| Other | — |
| Provision for income taxes | $ 8,322 |

## 14. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. In conjunction with our existing and anticipated debt instruments, we have executed the following derivative transactions:

*Hedges Against Interest Rate Increases on the Anticipated Refinancing of the Magellan Pipeline Notes*

In February 2004, we entered into three separate interest rate swap agreements to hedge our exposure to changes in interest rates for a portion of the debt we anticipated refinancing related to Magellan Pipeline's Series

A and Series B senior notes (see Note 15 – Debt). The notional amounts of the swaps totaled $150.0 million. The 10-year period of the swap agreements was the assumed tenure of the replacement debt starting in October 2007. The average fixed rate on the swap agreements was 5.9%.

*Hedges Against Interest Rate Increases on a Portion of the Notes Issued in May 2004*

In April 2004, we entered into three agreements for treasury lock transactions to hedge our exposure against interest rate increases for a portion of the $250.0 million of 10-year notes we issued in connection with our May 2004 refinancing plan (see Note 3—Debt and Equity Offerings for a discussion of our May 2004 refinancing plan). The notional amount of the agreements totaled $150.0 million and extended from 2004 to 2014 at a weighted average interest rate of 4.4%.

*Impact of Unwinding the Above Hedges*

During May 2004, we unwound the interest rate swap agreements described above and realized a gain of $3.2 million. We also unwound the treasury lock transactions described above in May 2004 and realized a gain of $2.9 million. Because the interest rate swap hedges were considered to be effective, all of the realized gain associated with the interest rate swaps was recorded to other comprehensive income and is being amortized over the 10-year life of the notes issued during May 2004. Because the combined notional amounts of the interest rate swap agreements and the treasury locks exceeded the total amount of debt issued, a portion of the treasury lock hedge was ineffective. As such, the portion of the realized gain associated with the ineffective portion of the treasury lock hedge, or $1.0 million, was recorded as a gain on derivative during May 2004. The remainder of the $1.9 million gain realized on the treasury lock hedge, was recorded to other comprehensive income and is being amortized over the 10-year life of the notes issued during May 2004.

*Fair Value Hedges on a Portion of the Magellan Pipeline Notes*

During May 2004, we entered into four separate interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline Series B senior notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the interest rate swap agreements, we receive 7.7% (the weighted-average interest rate of the Magellan Pipeline Series B senior notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007, the maturity date of the Magellan Pipeline Series B senior notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period we will record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 1.0% change in LIBOR would result in an annual adjustment to our interest expense associated with this hedge of $2.5 million. The fair value of the instruments associated with this hedge at December 31, 2004 was $2.7 million and was recorded to other noncurrent assets and long-term debt.

*Hedges Against Interest Rate Increases on a Portion of the Senior Notes Issued in October 2004*

In July 2004, we entered into two agreements for forward starting swaps to hedge our exposure to changes in interest rates for a portion of the $250.0 million of senior notes we anticipated issuing during October 2004 as partial financing for the assets we acquired from Shell. The notional amounts of the agreements totaled $150.0 million. On October 7, 2004, the date we issued $250.0 million of notes due 2016, we unwound these hedges and realized a loss of $6.3 million. Because the hedges were considered to be effective, all of the realized loss associated with the hedges was recorded to other comprehensive income and is being amortized over the 12-year life of the notes issued in October 2004.

*Fair Value Hedges on a Portion of the Senior Notes Issued in October 2004*

In October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016 which were issued in October 2004. The notional amount of this agreement is $100.0 million and effectively converts $100.0 million of our 5.65% fixed-rate senior notes issued in October 2004 to floating-rate debt. The agreement began on October 7, 2004 and terminates on October 15, 2016, which is the maturity date of the senior notes due 2016. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period we will record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 1.0% change in LIBOR would result in an annual adjustment to our interest expense of $1.0 million associated with this hedge. The fair value of this hedge at December 31, 2004 was $0.8 million and was recorded to other noncurrent assets and long-term debt.

## 15. Debt

Our debt at December 31, 2003 and 2004 was as follows (in thousands):

| | December 31, | |
|---|---|---|
| | 2003 | 2004 |
| August 2003 term loan and revolving credit facility: | | |
| Long-term portion | $ 89,100 | |
| Current portion | 900 | |
| Total August 2003 term loan and revolving credit facility | 90,000 | |
| Magellan Pipeline Notes | 480,000 | 304,674 |
| 6.45% Notes due 2014 | — | 250,292 |
| 5.65% Notes due 2016 | — | 249,702 |
| Total debt | $570,000 | $804,668 |

Maturities of long-term debt outstanding as of December 31, 2004, excluding market value adjustments to long-term debt associated with qualifying hedges, are as follows: $15.1 million—2005; $14.3 million—2006; $272.6 million—2007; $0—2008 and 2009; and $500.0 million thereafter.

*5.65% Notes due 2016*

On October 7, 2004, we issued $250.0 million of senior notes due 2016. The notes were issued for the discounted price of 99.9%, or $249.7 million. Including the impact of hedges associated with these notes (see Note 14–Derivative Financial Instruments), the effective interest rate of these notes during 2004 was 5.1%. Interest is payable semi-annually in arrears on April 15 and October 15 of each year, commencing on April 15, 2005. The discount on the notes is being accreted over the life of the notes.

*6.45% Notes due 2014*

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

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

*May 2004 Revolving Credit Facility*

In connection with our May 2004 refinancing, we entered into a five-year $125.0 million revolving credit facility with a syndicate of banks. In September 2004, we increased the facility to $175.0 million. As of December 31, 2004, $1.1 million of the facility was being used for letters of credit with no other amounts outstanding. Borrowings under this revolving credit facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.6% to 1.5% based on our credit ratings.

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

*Magellan Pipeline Notes*

During October 2002, Magellan Pipeline entered into a private placement debt agreement with a group of financial institutions for $178.0 million of floating rate Series A Senior Secured Notes and $302.0 million of fixed rate Series B Senior Secured Notes. Both notes were secured with our membership interest in and assets of Magellan Pipeline until our refinancing plan was executed in May 2004 (see Note 3–Debt and Equity Offerings). As part of that refinancing, the $178.0 million outstanding balance of the floating rate Series A Senior Secured Notes was repaid. In addition, the fixed rate Series B noteholders released the collateral which secured those notes except for cash deposited in an escrow account in anticipation of semi-annual interest payments on the Magellan Pipeline notes. The maturity date of the Series B senior notes is October 7, 2007; however, we will be required on each of October 7, 2005 and October 7, 2006, to repay 5.0% of the principal amount outstanding on those dates. The outstanding principal amount of the Series B senior notes at December 30, 2004 was $302.0 million; however, the recorded amount was increased by $2.7 million for the change in the fair value of the debt from May 25, 2004 through December 31, 2004 in connection with the associated fair value hedge (see Note 14–Derivative Financial Instruments). The interest rate of the Series B senior notes is fixed at 7.7%. However, including the impact of the associated fair value hedge, which effectively swaps $250.0 million of the fixed-rate Series B senior notes to floating-rate debt (see Note 14–Derivative Financial Instruments), the weighted-average interest rate for the Series B senior notes was 6.9% for the twelve months ended December 31, 2004, respectively. The weighted-average interest rate for the Series A and Series B senior notes combined (including the impact of the associated hedge) for the twelve months ended December 31, 2004 was 6.5%.

Deposits for interest due the lenders are made to a cash escrow account and were reflected as restricted cash on our consolidated balance sheets of $8.2 million and $5.8 million at December 31, 2003 and 2004, respectively.

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

*August 2003 Term Loan and Revolving Credit Facility*

In August 2003, we entered into a credit agreement with a syndicate of banks. This facility was comprised of a $90.0 million term loan and an $85.0 million revolving credit facility. Indebtedness under the term loan incurred interest at LIBOR plus a margin of 2.0%, while indebtedness under the revolving credit facility incurred interest at LIBOR plus a margin of 1.8%. In May 2004, we repaid the $90.0 million outstanding term loan and this facility was replaced with the revolving credit agreement described above.

During the years ending December 31, 2002, 2003 and 2004, total cash payments for interest on all indebtedness, net of amounts capitalized, were $18.0 million, $32.4 million and $35.8 million, respectively.

## 16. Leases

***Leases—Lessee***

We lease land, office buildings, tanks and terminal equipment at various locations to conduct our business operations. Several of the agreements provide for negotiated renewal options and cancellation penalties, some of which include the requirement to remove our pipeline from the property for non-performance. Total rent expense was $5.6 million, $3.9 million and $4.7 million in 2002, 2003 and 2004, respectively. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2004, are as follows (in thousands):

| | |
|---|---|
| 2005 | $ 2,623 |
| 2006 | 2,711 |
| 2007 | 2,652 |
| 2008 | 2,024 |
| 2009 | 1,413 |
| Thereafter | 12,113 |
| Total | $23,536 |

***Leases—Lessor***

We have ten capacity leases with remaining terms from one to 12 years that we account for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum lease payments receivable under operating-type leasing arrangements as of December 31, 2004, are as follows (in thousands):

| | |
|---|---|
| 2005 | $ 9,210 |
| 2006 | 8,337 |
| 2007 | 7,791 |
| 2008 | 7,636 |
| 2009 | 6,724 |
| Thereafter | 16,641 |
| Total | $56,339 |

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

Future minimum lease payments receivable under direct-financing-type leasing arrangements as of December 31, 2004, were $1.4 million in 2005, $1.3 million in 2006, $1.3 million in 2007, $1.3 million in 2008, $1.3 million in 2009 and $8.8 million cumulatively for all periods after 2009. The net investment under direct financing leasing arrangements as of December 31, 2003 and 2004, were as follows (in thousands):

| | December 31, | |
|---|---|---|
| | 2003 | 2004 |
| Total minimum lease payments receivable | $17,699 | $15,351 |
| Less: Unearned income | 8,469 | 7,245 |
| Recorded net investment in direct financing leases | $ 9,230 | $ 8,106 |

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

| | December 31, | |
|---|---|---|
| | 2003 | 2004 |
| Classification of direct financing leases: | | |
| Current accounts receivable | $ 378 | $ 423 |
| Current deferred revenue | (225) | — |
| Noncurrent accounts receivable | 9,077 | 7,683 |
| Total | $9,230 | $8,106 |

## 17. Long-Term Incentive Plan

In February 2001, our 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 us and directors of our general partner. The Long-Term Incentive Plan consists of two components: phantom units and unit options. The Long-Term Incentive Plan permits the grant of awards covering an aggregate of 700,000 common units. The Compensation Committee of our general partner's Board of Directors administers the Long-Term Incentive Plan.

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

In April 2001, our general partner granted 64,200 phantom units pursuant to the Long-Term Incentive Plan. With the change in control of our general partner in June 2003, these awards vested at their maximum award level, resulting in 128,400 unit awards. We recognized compensation expense associated with these awards of $1.5 million and $3.4 million during 2002 and 2003, respectively.

During 2002, our general partner granted 22,650 phantom units pursuant to the Long-Term Incentive Plan. With the change in control of our general partner in June 2003, these awards vested at their maximum award level, resulting in 45,300 unit awards. We recognized compensation expense associated with these awards of $0.2 million and $2.0 million during 2002 and 2003, respectively.

In February 2003, our 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 we determined 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. 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 under certain circumstances. During 2003, we increased the associated accrual to an expected payout of 95,271 units with further adjustments to the expected unit payouts during 2004 for employee terminations and retirements. Accordingly, we recorded incentive compensation expense of $1.7 million and $2.2 million associated with these phantom awards during 2003 and 2004, respectively. The value of the 92,989 phantom unit awards being accrued was $5.5 million at December 31, 2004.

Following the change in control of our general partner in June 2003 from Williams to MMH, the board of directors of our general partner made the following grants to certain employees who became dedicated to providing services to us:

- In October 2003, our 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, 470 units vested on July 31, 2004 and 4,850 units on December 31, 2004. The remaining 470 units will vest 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 under certain circumstances. We recorded $0.3 million and $0.2 million of compensation expense associated with these awards during 2003 and 2004, respectively. The value of the 470 unvested awards at December 31, 2004 was less than $0.1 million.
- On January 2, 2004, our general partner granted 10,856 phantom units pursuant to the Long-Term Incentive Plan. Of these awards, 5,433 units vested on July 31, 2004 and 5,423 units will vest 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 under certain circumstances. We recorded $0.5 million of compensation expense associated with these awards during 2004. The value of the 5,423 unvested awards at December 31, 2004 was $0.3 million.

In February 2004, our general partner granted 79,512 phantom units pursuant to the Long-Term Incentive Plan. The actual number of units that will be awarded under this grant are based on the attainment of short-term and long-term performance metrics. The number of phantom units that could ultimately be issued under this award range from zero units up to a total of 159,024 units; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 40%. The units will vest at the end of 2006. 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 under certain circumstances. During 2004 we increased our estimate of the number of units that will be awarded under this grant to 144,813 based on the expected attainment of the short-term performance metrics and the probability of attaining higher-than-standard on the long-term performance metrics and accordingly recognized $2.8 million of compensation expense during 2004. The value of the 144,813 unit awards on December 31, 2004 was $8.5 million.

Our equity-based incentive compensation costs for 2002, 2003 and 2004 are summarized as follows (in thousands):

| | 2002 | 2003 | 2004 |
|---|---|---|---|
| IPO awards | $2,051 | $ — | $ — |
| 2001 awards | 1,472 | 3,373 | — |
| 2002 awards | 185 | 1,955 | — |
| 2003 awards | — | 1,740 | 2,232 |
| October 2003 awards | — | 309 | 199 |
| January 2004 awards | — | — | 500 |
| 2004 awards | — | — | 2,809 |
| Total | $3,708 | $7,377 | $5,740 |

## 18. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based upon segment operating margin, which includes revenues from affiliates and external customers, operating expenses, environmental expenses, environmental reimbursements, product purchases and equity earnings.

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

The non-generally accepted accounting principle measure of operating margin (in the aggregate and by segment) is presented in the following tables. The components of operating margin are computed by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Management believes that investors benefit from having access to the same financial measures they use to evaluate performance. Operating margin is an important performance measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and G&A costs, that management does not consider when evaluating the core profitability of an operation.

| | Twelve Months Ended December 31, 2002 | | | |
|---|---|---|---|---|
| | Petroleum Products Pipeline System | Petroleum Products Terminals | Ammonia Pipeline System | Total |
| | (in thousands) | | | |
| Transportation revenues: | | | | |
| Third party | $239,327 | $ 78,083 | $13,135 | $ 330,545 |
| Affiliate | 33,195 | — | — | 33,195 |
| Product sales revenues: | | | | |
| Third party | 43,979 | 1,360 | — | 45,339 |
| Affiliate | 25,188 | — | — | 25,188 |
| Affiliate management fee revenues | 210 | — | — | 210 |
| 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 G&A 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 |

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

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

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

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

| | Year Ended December 31, 2004 | | | | |
|---|---|---|---|---|---|
| | Petroleum Products Pipeline System | Petroleum Products Terminals | Ammonia Pipeline System | Intersegment Eliminations | Total |
| | | | (in thousands) | | |
| Transportation revenues | $ 312,335 | $ 91,302 | $13,922 | $(1,151) | $ 416,408 |
| Product sales revenues | 267,659 | 10,819 | — | — | 278,478 |
| Affiliate management fee revenue | 488 | — | — | — | 488 |
| Total revenues | 580,482 | 102,121 | 13,922 | (1,151) | 695,374 |
| Operating expenses | 138,957 | 36,864 | 5,300 | (4,180) | 176,941 |
| Environmental | 38,744 | 3,039 | 2,206 | — | 43,989 |
| Environmental reimbursements | (37,647) | (2,839) | (912) | — | (41,398) |
| Product purchases | 249,189 | 6,535 | — | — | 255,724 |
| Equity earnings | (1,602) | — | — | — | (1,602) |
| Operating margin | 192,841 | 58,522 | 7,328 | 3,029 | 261,720 |
| Depreciation and amortization | 24,970 | 13,375 | 471 | 3,029 | 41,845 |
| Affiliate G&A expenses | 38,335 | 13,781 | 2,350 | — | 54,466 |
| Segment profit | $ 129,536 | $ 31,366 | $ 4,507 | $ — | $ 165,409 |
| Segment assets | $1,246,083 | $398,220 | $24,590 | | $1,668,893 |
| Corporate assets | | | | | 148,939 |
| Total assets | | | | | $1,817,832 |
| Goodwill | — | 22,007 | — | — | 22,007 |
| Additions to long-lived assets | 547,868 | 53,659 | 521 | — | 602,048 |

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

## 19. Commitments and Contingencies

Prior to May 27, 2004, we had three separate indemnification agreements with Williams. These three agreements are described below:

*IPO Indemnity Agreement*—Williams and certain of its affiliates indemnified us for covered environmental losses up to $15.0 million related to assets operated by us at the time of our initial public offering date (February 9, 2001) that became known by August 9, 2004 and that exceed amounts recovered or recoverable under our contractual indemnities from third persons or under any applicable insurance policies. We refer to this indemnity as the "IPO Indemnity". Covered environmental losses included those non-contingent terminal and ammonia system environmental losses, costs, damages and expenses suffered or incurred by us 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. In addition, Williams and certain of its affiliates indemnified us 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 also indemnified us 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.

*Magellan Pipeline Indemnity Agreement*—In conjunction with the acquisition of Magellan Pipeline in April 2002, Williams agreed to indemnify us for any breaches of representations or warranties, environmental liabilities and failures to comply with environmental laws. Williams' liability under this indemnity was capped at $125.0 million. We refer to this indemnity as the "Magellan Pipeline Indemnity". In addition to environmental liabilities, this indemnity included matters relating to employees and employee benefits and real property, including asset titles. Also, this indemnity provided that we were indemnified for an unlimited amount of losses and damages related to tax liabilities. The environmental liability indemnity included any losses and damages related to environmental liabilities caused by events that occurred prior to the acquisition. 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.

*Acquisition Indemnity Agreement*—In addition to these two agreements, the purchase and sale agreement ("June 2003 Agreement") entered into in connection with MMH's acquisition of Williams' partnership interest in us provided us with two additional indemnities related to environmental liabilities, which we collectively refer to as the "Acquisition Indemnity".

First, MMH assumed Williams' obligations to indemnify us for $21.9 million of known environmental liabilities.

Second, in the June 2003 Agreement, 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 the IPO Indemnity and Magellan Pipeline Indemnity agreements described above. This additional indemnification included those liabilities related to the 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 covered environmental as well as other liabilities.

*Indemnification Settlement*—In May 2004, our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from the environmental indemnifications and certain other indemnifications described under the IPO Indemnity, Magellan Pipeline Indemnity and Acquisition Indemnity agreements described above. We received $35.0 million from Williams on July 1, 2004 and expect to receive installment payments from Williams of $27.5 million, $20.0 million and $35.0 million on July 1, 2005, 2006 and 2007, respectively. The $35.0 million amount received in July 2004 was recorded as a reduction to our receivable with Williams. Following this payment, our receivable balance with Williams, which remained unchanged through December 31, 2004, was $10.1 million. When the $27.5 million payment from Williams is received in July 2005, we will record $10.1 million as a reduction in our receivable balance with Williams with the remaining $17.4 million recorded as a capital contribution from our general partner. The final two installment payments from Williams will be recorded as capital contributions from our general partner when the cash amounts have been received from Williams.

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

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

*Environmental Liabilities*—Estimated liabilities for environmental costs were $26.8 million and $60.8 million at December 31, 2003 and 2004, respectively. These estimates are provided on an undiscounted basis and have been classified as current or non-current based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years. As of December 31, 2004, known liabilities that would have been covered by the three indemnity agreements discussed above were $40.8 million.

*Environmental Receivables*—As part of its negotiations with Williams for the June 2003 acquisition of Williams' interest in us, MMH assumed Williams' obligations for $21.9 million of environmental liabilities and we recorded a receivable from MMH for this amount. To the extent the environmental and other Williams indemnity claims against MMH are less than $21.9 million, MMH will pay to Williams the remaining difference between $21.9 million and the indemnity claims paid by MMH. Environmental receivables from MMH at December 31, 2003 and 2004 were $19.0 million and $11.5 million, respectively. Environmental receivables from insurance carriers were $3.1 million and $7.4 million at December 31, 2003 and 2004, respectively. We invoice MMH and third-party insurance companies for reimbursement as environmental remediation work is performed. Receivables from Williams or its affiliates associated with indemnified environmental costs were $7.8 million at December 31, 2003.

*Other Indemnifications*—In conjunction with the 1999 acquisition of the Gulf Coast marine terminals from Amerada Hess Corporation ("Hess"), Hess represented that it had disclosed to us all suits, actions, claims, arbitrations, administrative, governmental investigation or other legal proceedings pending or threatened, against or related to the assets we acquired, which arise under environmental law. Our agreement with Hess provided that in the event that any pre-acquisition releases of hazardous substances at the Corpus Christi and Galena Park, Texas and Marrero, Louisiana marine terminal facilities were unknown at closing but subsequently identified by us prior to July 30, 2004, we would be liable for the first $2.5 million of environmental liabilities, Hess would be liable for the next $12.5 million of losses and we would assume responsibility for any losses in excess of $15.0 million. Also, Hess agreed to indemnify us 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 further indemnified us for certain pre-acquisition fines and claims that may be imposed or asserted against us under certain environmental laws. We have filed claims with Hess associated with their indemnifications to us totaling $1.9 million. Our claims stated that remediation expenditures beyond our initial $1.9 million claim may be necessary and that our claims would be increased for any expenditures required beyond this amount. We are currently in the process of negotiating a settlement of these claims with Hess.

*EPA Issue*—In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to Williams based on a preliminary determination that Williams may have systematic problems with petroleum discharges from pipeline operations. That inquiry primarily focused on Magellan Pipeline. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those spills may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these spills if the EPA were to successfully seek and obtain injunctive relief. We have verbally agreed to a response schedule for the 32 releases and have submitted a response in accordance to that schedule. We have met with the EPA and the DOJ and anticipate negotiating a final settlement with both agencies by the end of 2005. We have evaluated this issue and have accrued an amount based on our best estimates that is less than $22.0 million. This liability was covered under the environmental indemnification settlement with Williams in May 2004.

*Shawnee, Kansas Spill*—During the fourth quarter of 2003, we experienced a line break and product spill on our petroleum products pipeline near Shawnee, Kansas. As of December 31, 2004, we estimated the total costs associated with this spill to be $10.1 million. We have spent $8.4 million on remediation at this site, leaving a remaining liability on our balance sheet at December 31, 2004 of $1.7 million. At December 31, 2004, we had recorded a receivable from our insurance carrier of $7.4 million related to this spill.

*Other*—We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, the ultimate resolution of 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 our future financial position, results of operations or cash flows.

## 20. 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 |
| Operating margin | 57,927 | 53,460 | 54,643 | 52,340 |
| 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 |
| **2004** | | | | |
| Revenues | $133,144 | $142,220 | $158,500 | $261,510 |
| Operating margin | 56,975 | 66,861 | 62,628 | 75,256 |
| Total costs and expenses | 98,698 | 98,836 | 119,986 | 214,047 |
| Net income | 25,815 | 18,457 | 30,603 | 35,328 |
| Basic net income per limited partner unit | 0.87 | 0.63 | 0.97 | 0.96 |
| Diluted net income per limited partner unit | 0.87 | 0.63 | 0.96 | 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 our 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. Third and fourth quarter results were impacted by our petroleum products management operation acquisition in July 2003.

All 2004 quarters were impacted by the results from our acquisition of 14 terminals in January 2004 and our equity investment in Osage Pipeline in March 2004. Second-quarter 2004 results were impacted by $16.7 million of refinancing costs, which included $12.7 million of debt prepayment premiums associated with the early extinguishment of a portion of our previously outstanding Magellan Pipeline Series A senior notes, a $5.0 million write-off of unamortized debt placement costs associated with the retired debt and a $1.0 million gain on an interest rate hedge related to the debt refinancing. Fourth-quarter 2004 results were impacted by our acquisition of certain assets from Shell (see Note 6—Acquisitions). Fourth-quarter 2004 results were also impacted by the interest costs associated with $250.0 million of additional debt incurred to help finance the assets acquired from Shell.

## 21. Fair Value of Financial Instruments

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

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

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

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

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

*Long-term debt:* For 2003, the carrying amount of our variable-rate debt approximates fair value. For 2003, the fair value of our fixed-rate debt was determined by discounting estimated future cash flows using our incremental borrowing rate. For 2004, the fair value of traded notes was based on the prices of those notes at December 31, 2004. The fair value of our private placement debt was determined by discounting estimated future cash flows using our incremental borrowing rate.

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

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2003 and 2004 (in thousands):

| | December 31, 2003 | | December 31, 2004 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | $111,357 | $111,357 | $ 29,833 | $ 29,833 |
| Restricted cash | 8,223 | 8,223 | 5,847 | 5,847 |
| Marketable securities | — | — | 87,802 | 87,802 |
| Long-term affiliate receivables | 13,472 | 11,408 | 4,599 | 4,035 |
| Long-term receivables | 9,077 | 8,032 | 8,070 | 7,159 |
| Debt | 570,000 | 577,510 | 802,000 | 845,248 |
| Interest rate swaps | — | — | 3,459 | 3,459 |

## 22. Distributions

We paid the following distributions during 2002, 2003 and 2004 (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 | Total Cash Distribution |
|---|---|---|---|---|---|---|
| 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 |
| 02/13/04 | $0.8300 | $18,020 | $ 4,714 | $ — | $ 3,066 | $ 25,800 |
| 05/14/04 | 0.8500 | 19,661 | 3,621 | — | 3,613 | 26,895 |
| 08/13/04 | 0.8700 | 20,994 | 3,706 | — | 4,313 | 29,013 |
| 11/12/04 | 0.8900 | 25,739 | 3,791 | — | 5,705 | 35,235 |
| Total | $3.4400 | $84,414 | $15,832 | $ — | $16,697 | $116,943 |

On February 14, 2005, we paid cash distributions of $0.9125 per unit on our outstanding common and subordinated units to unitholders of record at the close of business on February 8, 2005. The total distribution, including distributions paid to our general partner on its equivalent units, was $35.5 million. In connection with the October 2004 acquisition of assets from Shell, our partnership agreement was amended to reduce the incentive cash distribution paid to our general partner by $5.0 million for 2005. Accordingly, we reduced the cash distribution paid to our general partner on February 14, 2005, by $1.25 million.

## 23. 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, 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 | (.01) |
| Diluted net income per limited partner unit | $ 80,713 | 21,968 | $3.67 |

| | 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, 2004 | | |
|---|---|---|---|
| | Income (Numerator) | Units (Denominator) | Per Unit Amount |
| Limited partners' interest in income | $101,140 | | |
| Basic net income per limited partner unit | $101,140 | 29,358 | $3.45 |
| Effect of dilutive restrictive unit grants | — | 64 | (.01) |
| Diluted net income per limited partner unit | $101,140 | 29,422 | $3.44 |

Units reported as dilutive securities are related to restricted unit grants associated with unvested awards (see Note 17—Long-Term Incentive Plan).

## 24. Partners' Capital

Of the 28,920,541 common units outstanding at December 31, 2004, the public held 26,185,000, with the remaining 2,735,541 held by affiliates of ours. All of the 4,259,771 subordinated units were held by affiliates of ours.

During the subordination period, we can issue up to 2,839,847 additional common units without obtaining unitholder approval. In December 2003 we issued 200,000 units, which reduced the number of additional common units we can issue without unitholder approval to 2,639,847. Additionally, in May 2004 we issued 1.0 million units to the public, of which 219,000 were applicable to previous investments with the remaining 781,000 units used to complete our refinancing plan. The units used for the refinancing plan reduced the number of additional common units we can issue without unitholder approval to 1,858,847. Our general partner can issue an unlimited number of parity common units as follows:

- 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 our 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 we meet certain financial tests provided for in our partnership agreement but it generally cannot end before December 31, 2005.

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

- right to receive distributions of our available cash within 45 days after the end of each quarter;
- right to elect the board members of our general partner;
- right to remove Magellan GP, LLC as our general partner upon a 66.7% majority vote of outstanding unitholders;
- right to transfer common unit ownership to substitute limited partners;
- right to receive an annual report, containing audited financial statements and a report on those financial statements by our independent public accountants within 120 days after the close of the fiscal year end;
- right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year;
- right to vote according to the limited partners' percentage interest in us on any meeting that may be called by our general partner; and
- right to inspect our books and records at the unitholders' own expense.

Net income is allocated to our general partner and limited partners based on their proportionate share of cash distributions for the period. Cash distributions to our 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.

## 25. Subsequent Events

On January 4, 2005, MMH sold 2,735,541 common units representing limited partner interests in us in a privately negotiated transaction. Also during February 2005, MMH sold an additional 225,144 common units representing limited partner interests in us in another privately negotiated transaction. Following these sales, MMH's ownership interest in us, including their general partner interest, decreased from 23% to 14%.

On February 8, 2005, one day after our quarterly cash distribution record date, 1,419,923 of the subordinated units owned by MMH converted to common units as provided in our partnership agreement.

On February 14, 2005, we paid cash distributions of $0.9125 per unit on our outstanding common and subordinated units to unitholders of record at the close of business on February 8, 2005. The total distribution, including distributions paid to our general partner on its equivalent units, was $35.5 million. In connection with the October 2004 acquisition of assets from Shell, our partnership agreement was amended to reduce the incentive cash distribution paid to our general partner by $5.0 million for 2005. Accordingly, we reduced the cash distribution paid to our general partner on February 14, 2005, by $1.25 million.

In February 2005, our general partner granted 79,970 phantom units pursuant to the Long-Term Incentive Plan.

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

None

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

**Disclosure Controls and Procedures**

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including the General Partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, the General Partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. There has been no change in our internal control over financial reporting (as defined in Rule 13a – 15(f) of the Securities and Exchange Act) during the quarter ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

**Management's Annual Report on Internal Control Over Financial Reporting**

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The term internal control over financial reporting is defined as a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with general accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention and timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on our financial statements. Management believes that the design and operation of our internal control over financial reporting at December 31, 2004 are effective.

We assessed our internal control system using the criteria for effective internal control over financial reporting described in "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations ("COSO" criteria) of the Treadway Commission. As of December 31, 2004, based on the results of our assessment, management believes that we have no material weaknesses in internal control over our financial reporting. In our opinion, we maintained effective internal control over financial reporting as of December 31, 2004, in all material respects, based on COSO criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on management's assessment of our internal control over financial reporting as of December 31, 2004. The report, which expresses unqualified opinions on management's assessment and on the effectiveness of our internal control over financial reporting as of December 31, 2004, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting."

By: /s/ Don R. Wellendorf

**Chairman of the Board, President, Chief Executive Officer and Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.**

By: /s/ John D. Chandler

**Vice President, Treasurer and Chief Financial Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.**

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

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

We have audited management's assessment, included in the accompanying "Management's Annual Report on Internal Control Over Financial Reporting", that Magellan Midstream Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO criteria"). Magellan Midstream Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Magellan Midstream Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2004 and 2003, and the related consolidated statements of income, cash flows and partners' capital for each of the three years in the period ended December 31, 2004 and our report dated March 7, 2005 expressed an unqualified opinion theron.

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
March 7, 2005

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

None

## PART III

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

The information regarding the directors and executive officers of our general partner required by Item 401 of Regulation S-K is presented in our proxy statement prepared for the solicitation of proxies in connection with our Annual Meeting of Limited Partners for 2005 (our "Proxy Statement") under the captions "Class III Director nominees", "Class I Directors", "Class II Directors" and "Executive Officers of our General Partner", which information is incorporated by reference herein. Information required by Item 405 of Regulation S-K is presented under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement, which information is incorporated by reference herein. Information required by Item 406 of Regulation S-K is presented under the caption "Code of Ethics" in our Proxy Statement, which information is incorporated by reference herein.

**ITEM 11.** ***Executive Compensation***

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

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

The information regarding securities authorized for issuance under equity compensation plans required by Item 201(d) of Regulation S-K is presented in our Proxy Statement under the caption "Equity Compensation – Securities Authorized for Issuance Under Equity Compensation Plans," which information is incorporated by reference herein. Information required by Item 403 of Regulation S-K is presented under the caption "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

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

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

**ITEM 14.** ***Principal Accountant Fees and Services***

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

## PART IV

**ITEM 15.** ***Exhibits and Financial Statement Schedules***

(a) 1 and 2.



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

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

| Exhibit No. | Description |
|---|---|
| Exhibit 2 | |
| *(a) | Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 99.1 to Form 8-K of The Williams Companies, Inc. filed April 21, 2003). |
| *(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. (filed as Exhibit 2(c) to Form 10-K filed March 10, 2004). |
| *(d) | Amendment No. 3 dated May 26, 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. (filed as Exhibit 2.1 to Form 10-Q filed August 6, 2004). |
| 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) | Third Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 22, 2004 (filed as Exhibit 3.1 to Form 10-Q filed May 7, 2004). |
| *(c) | Amendment No. 1 dated July 22, 2004 to Third Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 22, 2004 (filed as Exhibit 3.2 to Form 10-Q filed August 6, 2004). |
| *(d) | Amendment No. 2 dated July 22, 2004 to Third Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 22, 2004 (filed as Exhibit 3.3 to Form 10-Q filed August 6, 2004). |

| Exhibit No. | Description |
|---|---|
| *(e) | Amended and Restated Certificate of Formation of WEG GP LLC dated November 15, 2002, as amended on August 12, 2003 (filed as Exhibit 3(f) to Form 10-K filed March 10, 2004). |
| *(f) | Amended & Restated Limited Liability Company Agreement of Magellan GP, LLC dated December 1, 2003 (filed as Exhibit 3(g) to Form 10-K filed March 10, 2004). |
| *(g) | First Amendment dated February 3, 2004 to Amended & Restated Limited Liability Company Agreement of Magellan GP, LLC dated December 1, 2003 (filed as Exhibit 3(h) to Form 10-K filed March 10, 2004). |
| *(h) | Second Amendment dated May 21, 2004 to Amended & Restated Limited Liability Company Agreement of Magellan GP, LLC dated December 1, 2003 (filed as Exhibit 3.1 to Form 10-Q filed August 6, 2004). |
| Exhibit 4 | |
| *(a) | Third Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 22, 2004 (filed as Exhibit 3.1 to Form 10-Q filed May 7, 2004). |
| *(b) | Amendment No. 1 dated July 22, 2004 to Third Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 22, 2004 (filed as Exhibit 3.2 to Form 10-Q filed August 6, 2004). |
| *(c) | Amendment No. 2 dated July 22, 2004 to Third Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 22, 2004 (filed as Exhibit 3.3 to Form 10-Q filed August 6, 2004). |
| *(d) | Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004). |
| *(e) | First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004). |
| *(f) | Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004). |
| Exhibit 10 | |
| *(a) | Fourth Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated February 3, 2004 (filed as Exhibit 10(a) to Form 10-K filed March 10, 2004). |
| *(b) | Magellan Midstream Holdings, L.P. Pension Plan (filed as Exhibit 10(b) to Form 10-K filed March 10, 2004). |
| *(c) | Magellan Midstream Holdings, L.P. 401(k) Plan (filed as Exhibit 10(c) to Form 10-K filed March 10, 2004). |
| *(d) | Description of Magellan Midstream Holdings, L.P. 2005 Annual Incentive Program (filed as Exhibit 10.2 to Form 8-K filed February 2, 2005). |
| *(e) | Magellan Midstream Holdings, L.P. Severance Pay Plan effective as of January 1, 2004 (filed as Exhibit 10.1 to Form 10-Q filed May 7, 2004). |
| *(f) | Form of 2005 Phantom Unit Award Agreement pursuant to the Magellan Midstream Partners Long-Term Incentive Plan (filed as Exhibit 10.3 to Form 8-K filed February 2, 2005). |
| *(g) | Summary of Independent Director Compensation Program (filed as Exhibit 10.1 to Form 8-K/A filed February 3, 2005) |

| Exhibit No. | Description |
|---|---|
| *(h) | 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). |
| *(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) | First Amendment dated May 19, 2004 to Services Agreement dated June 17, 2003 among WEG GP LLC, Williams Energy Partners L.P. and WEG Acquisitions, L.P. (filed as Exhibit 10.4 to Form 10-Q filed August 6, 2004). |
| *(l) | $125,000,000 Revolving Loan Credit Agreement dated May 25, 2004 among Magellan Midstream Partners, L.P., the lenders party thereto, JPMorgan Chase Bank, as Administrative Agent, and J.P. Morgan Securities Inc. and Lehman Brothers Inc., as Joint Bookrunners and Lead Arrangers (filed as Exhibit 10.1 to Form 10-Q filed August 6, 2004). |
| *(m) | First Amendment dated September 9, 2004 to Credit Agreement dated May 25, 2004 among Magellan Midstream Partners, L.P., the lenders party thereto, JPMorgan Chase Bank, as Administrative Agent, and J.P. Morgan Securities Inc. and Lehman Brothers Inc., as Joint Bookrunners and Lead Arrangers (filed as Exhibit 10.1 to Form 10-Q filed November 4, 2004). |
| *(n) | Amended and Restated Note Purchase Agreement dated May 25, 2004 among Magellan Pipeline Company, LLC, Magellan Midstream Partners, L.P. and Magellan GP, LLC and each of the Holders thereto (filed as Exhibit 10.2 to Form 10-Q filed August 6, 2004). |
| *(o) | Consent and Amendment dated August 30, 2004 to Amended and Restated Note Purchase Agreement dated May 25, 2004 among Magellan Pipeline Company, LLC, Magellan Midstream Partners, L.P. and Magellan GP, LLC and each of the Holders thereto (filed as Exhibit 10.2 to Form 10-Q filed November 4, 2004). |
| *(p) | Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004). |
| *(q) | First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004). |
| *(r) | Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004). |
| *(s) | Agreement for the Release of Certain Indemnification Obligations dated May 26, 2004 among Magellan Midstream Holdings, L.P., Magellan GP, LLC and Magellan Midstream Partners, L.P. and The Williams Companies, Inc., Williams Energy Services, LLC, and Williams Natural Gas Liquids, Inc. and Williams GP LLC (filed as Exhibit 10.3 to Form 10-Q filed August 6, 2004). |
| *(t) | Purchase and Sale Agreement dated June 23, 2004 among Shell Pipeline Company LP, Equilon Enterprises LLC dba Shell Oil Products US and Magellan Midstream Partners, L.P. (filed as Exhibit 10.5 to Form 10-Q filed August 6, 2004). |
| *(u) | Amendment No. 1 dated September 28, 2004 to Purchase and Sale Agreement dated June 23, 2004 among Shell Pipeline Company LP, Equilon Enterprises LLC dba Shell Oil Products US and Magellan Midstream Partners, L.P. (filed as Exhibit 10.4 to Form 10-Q filed November 4, 2004). |

| Exhibit No. | Description |
|---|---|
| Exhibit 12 | Ratio of earnings to fixed charges. |
| Exhibit 14 | |
| *(a) | —Code of Ethics dated September 1, 2003 by Don R. Wellendorf, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed March 10, 2004). |
| *(b) | —Code of Ethics dated September 1, 2003 by John D. Chandler, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed March 10, 2004). |
| Exhibit 21 | —Subsidiaries of Magellan GP, LLC and Magellan Midstream Partners, L.P. |
| Exhibit 23 | —Consent of Independent Registered Public Accounting Firm. |
| Exhibit 31 | |
| (a) | —Certification of Don R. Wellendorf, principal executive officer. |
| (b) | —Certification of John D. Chandler, principal financial officer. |
| Exhibit 32 | |
| (a) | —Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer. |
| (b) | —Section 1350 Certification of John D. Chandler, Chief Financial Officer. |
| Exhibit 99 | —Magellan GP, LLC consolidated balance sheets at December 31, 2004 and 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.

## 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: /s/ MAGELLAN GP, LLC, its general partner

By: /s/ LONNY E. TOWNSEND
**Lonny E. Townsend,**
**Vice President and General Counsel**

Date: March 10, 2005

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

| Signature | Title | Date |
|---|---|---|
| /s/ DON R. WELLENDORF<br>**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, 2005 |
| /s/ JOHN D. CHANDLER<br>**John D. Chandler** | Vice President, Treasurer and Chief Financial Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ JIM H. DERRYBERRY<br>**Jim H. Derryberry** | Director of Magellan GP, LLC General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ PATRICK C. EILERS<br>**Patrick C. Eilers** | Director of Magellan GP, LLC General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ N. JOHN LANCASTER, JR.<br>**N. John Lancaster, Jr.** | Director of Magellan GP, LLC General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ JAMES R. MONTAGUE<br>**James R. Montague** | Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ GEORGE A. O'BRIEN, JR.<br>**George A. O'Brien, Jr.** | Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ MARK G. PAPA<br>**Mark G. Papa** | Director of Magellan GP, LLC General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |
| /s/ THOMAS S. SOULELES<br>**Thomas S. Souleles** | Director of Magellan GP, LLC General Partner of Magellan Midstream Partners, L.P. | March 10, 2005 |