Williams Partners L.P.
Form 10-K
March 03, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1933**

For the fiscal year ended December 31, 2005

or

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

For the transition period from to

Commission file number 1-32599
Williams Partners L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware	**20-2485124**
(State or Other Jurisdiction of Incorporation or Organization)	*(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma	**74172-0172**
(Address of Principal Executive Offices)	*(Zip Code)*

918-573-2000
(Registrant s Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Units	New York Stock Exchange

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

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

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

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 þ No o

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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

The registrant s common units were not publicly traded as of the last business day of the registrant s most recently completed second fiscal quarter. The aggregate market value of the registrant s common units held by non-affiliates of the registrant as of February 28, 2006 was $188,534,290 based on the closing sale price of such units as reported on the New York Stock Exchange on such date. This figure excludes common units beneficially owned by the directors and executive officers of Williams Partners GP LLC, our general partner.

The registrant had 7,006,146 common units and 7,000,000 subordinated units outstanding as of February 28, 2006.

DOCUMENTS INCORPORATED BY REFERENCE

None

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PART IV

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DEFINITIONS

We use the following oil and gas measurements and industry terms in this report:

Barrel: One barrel of petroleum products equals 42 U.S. gallons.

bpd: Barrels per day.

British Thermal Units (Btu): When used in terms of volumes, Btu is used to refer to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.

¢/ MMBtu: Cents per one million Btus.

Fractionation: The process by which a mixed stream of natural gas liquids is separated into its constituent products.

MMBtu: One million Btus.

MMBtu/d: One million Btus per day.

MMcf: One million cubic feet of natural gas.

MMcf/d: One million cubic feet of natural gas per day.

NGLs: Natural gas liquids.

Recompletions: After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well s productivity.

Throughput: The volume of product transported or passing through a pipeline, plant, terminal or other facility.

Workover: Operations on a completed production well to clean, repair and maintain the well for the purposes of increasing or restoring production.

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PART I

Items 1 and 2. ***Business and Properties***

References in this report to Williams Partners L.P., we, our, us or like terms, when used in a historical context prior to our initial public offering of common units on August 23, 2005 refer to the assets of The Williams Companies, Inc. and its subsidiaries that were contributed to Williams Partners L.P. and its subsidiaries in connection with that offering. When used in the context following the offering or prospectively, those terms refer to Williams Partners L.P. and its subsidiaries. In either case, unless the context clearly indicates otherwise, references to we, our and us include the operations of Discovery Producer Services LLC, or Discovery, in which we own a 40 percent interest. When we refer to Discovery by name, we are referring exclusively to its businesses and operations.

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other documents electronically with the SEC under the Securities Exchange Act of 1934, as amended. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. You may read and copy any materials that we file with the U.S. Securities and Exchange Commission (SEC) at the SEC s Public Reference Room at 450 Fifth Street, N.W., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC s Internet website at *http://www.sec.gov*.

We make available free of charge on or through our Internet website at *http://www.williamslp.com*, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, Code of Business Conduct and Ethics and the charters of the audit and compensation committees of our general partner s board of directors are also available on the Internet website.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

GENERAL

We are a Delaware limited partnership formed by The Williams Companies, Inc., or Williams, in February 2005 to own, operate and acquire a diversified portfolio of complementary energy assets. Williams is an integrated energy company with 2005 revenues in excess of $12.5 billion that trades on the New York Stock Exchange under the symbol WMB . Williams operates in a number of segments of the energy industry, including natural gas exploration and production, interstate natural gas transportation and midstream services. Williams has been in the midstream natural gas and NGL industry for more than 20 years.

We are principally engaged in the business of gathering, transporting and processing natural gas and the fractionating and storing of natural gas liquids. Fractionation is the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane. These natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels and gasoline additives, among other applications.

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Our asset portfolio consists of:

- a 40 percent interest in Discovery, which owns an integrated natural gas gathering and transportation pipeline system extending from offshore in the Gulf of Mexico to a natural gas processing facility and a natural gas liquids fractionator in Louisiana;

- the Carbonate Trend natural gas gathering pipeline off the coast of Alabama; and

- three integrated natural gas liquids storage facilities and a 50 percent interest in a natural gas liquids fractionator near Conway, Kansas.

These assets were owned by Williams prior to the initial public offering (IPO) of our common units in August 2005. Williams indirectly owns an approximate 59 percent limited partnership interest in us and all of our two percent general partner interest.

Initial Public Offering and Concurrent Transactions

On August 23, 2005, we completed our IPO of 5,000,000 common units representing limited partner interests in us at a price of $21.50 per unit. Concurrent with the closing of the IPO, a 40 percent interest in Discovery and all of the interests in Carbonate Trend Pipeline LLC and Mid-Continent Fractionation and Storage, LLC were contributed to us by Williams subsidiaries in exchange for an aggregate of 2,000,000 common units and 7,000,000 subordinated units. The public, through the underwriters of the offering, contributed $107.5 million ($100.2 million net of the underwriters discount and a structuring fee) to us in exchange for 5,000,000 common units, representing a 35 percent limited partner interest in us. Additionally, at the closing of the IPO the underwriters fully exercised their option to purchase 750,000 common units from Williams subsidiaries at the IPO price of $21.50 per unit, less the underwriters discount and a structuring fee. The proceeds were used to redeem in equal amount of common units redeemed by Williams, leaving Williams with 1,250,000 common units.

RECENT EVENTS

Discovery Open Season

In October 2005, Discovery offered firm transportation capacity through two expedited open seasons to help ensure natural gas that was stranded as a result of Gulf Coast hurricanes could quickly reach domestic markets. The first open season, offering up to 250,000 MMBtu/d of firm transportation, included the construction of a new receipt point, which was completed on December 2, 2005. Under this open season natural gas flows from the Venice, Louisiana area of Texas Eastern Transmission s interstate pipeline network to Discovery s Larose, Louisiana plant for processing. The processed gas is then transported back to Texas Eastern through an existing delivery point. Approximately 300,000 MMBtu/d is now flowing pursuant to this first open season. As a result of the second open season, an additional 175,000 MMBtu/d was subscribed and approximately 91,000 MMbtu/d flowed for 2005. Under this open season natural gas flowed via the reversal of an existing interconnection. Throughput under this second open season has fallen to approximately 35,000 MMBtu/d as some of the processing facilities on Tennessee gas Pipeline have returned to service. Discovery plans to provide the transportation and processing services associated with the open seasons at least through the first quarter of 2006.

Potential Acquisition Candidate Identified

On November 1, 2005, we announced that we and Williams had identified an approximate 25 percent interest in Williams existing gathering and processing assets in the Four Corners area as our initial candidate to be considered for acquisition. The terms of this proposed transaction, including price, will be subject to approval by the boards of directors of our general partner and of Williams.

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FINANCIAL INFORMATION ABOUT SEGMENTS

See Part II, Item 8 Financial Statements and Supplementary Data

NARRATIVE DESCRIPTION OF BUSINESS

We are principally engaged in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. Operations of our businesses are located in the United States and are organized into two reporting segments: (1) Gathering and Processing and (2) NGL Services. Our Gathering and Processing segment includes our equity investment in Discovery and the Carbonate Trend gathering pipeline. Our NGL Services segment includes the Conway fractionation and storage operations.

Gathering and Processing The Discovery Assets

General

We own a 40 percent interest in Discovery, which in turn owns:

- a 273-mile natural gas gathering and transportation pipeline system, located primarily off the coast of Louisiana in the Gulf of Mexico, with a capacity, certified by the U.S. Federal Energy Regulatory Commission (FERC), of approximately 600 MMcf/d on its mainline;
- a cryogenic natural gas processing plant in Larose, Louisiana with a capacity of approximately 600 MMcf/d;
- a fractionator in Paradis, Louisiana with a current capacity of approximately 32,000 bpd (which can be expanded to 42,000 bpd); and
- two onshore liquids pipelines, including a 22-mile mixed NGL pipeline connecting the gas processing plant to the fractionator and a 10-mile condensate pipeline connecting the gas processing plant to a third party oil gathering facility.

Although Discovery includes fractionation operations, which would normally fall within the NGL Services segment, it is primarily engaged in gathering and processing and is managed as such. Accordingly, this equity investment is considered part of the Gathering and Processing segment.

Additionally, Discovery recently signed definitive agreements with Chevron, Shell and Statoil to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion is expected to have a design capacity of approximately 200 MMcf/d, and its anticipated completion date is May 2007.

Discovery Natural Gas Pipeline System

Transportation and Gathering Natural Gas Pipeline. The mainline of the Discovery pipeline system consists of a 105-mile, 30-inch diameter natural gas and condensate pipeline, which begins at a platform, owned by a third party, located in the offshore Louisiana Outer Continental Shelf at Ewing Bank 873 and extends northerly to the Larose gas processing plant and a four-mile, 20-inch natural gas pipeline that connects the Larose plant to the Texas Eastern Pipeline. Approximately 66 miles of the mainline is located offshore, in water depths ranging from approximately 40 to 800 feet. Producers have dedicated their production from approximately 60 offshore blocks to Discovery. Each block represents an area of 5,760 square acres. The mainline has a FERC-certificated capacity of approximately 600 MMcf/d.

The Discovery system connects to five natural gas pipeline systems, two of which provide 1.3 Bcf/d of takeaway capacity: the Bridgeline system, which serves southern Louisiana and connects to the Henry Hub natural gas market point, and the Texas Eastern Pipeline system, which serves markets from Texas to the northeastern United States. Additionally, Discovery s recently completed market expansion project connects Discovery to the following pipeline systems: Tennessee Gas Pipeline, Columbia Gulf Transmission and

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Transcontinental Gas Pipe Line, or Transco. Together, these three pipeline systems provide up to an additional 500 MMcf/d of takeaway capacity. This market expansion project, consisting of approximately 40 miles of 20-inch diameter pipe extending from the Larose processing plant to Pointe Au Chien, Louisiana and Old Lady Lake, Louisiana commenced operations in June 2005 and has a FERC-certificated capacity of approximately 150 MMcf/d. Discovery s interconnections allow producers to benefit from flexible and diversified access to a variety of natural gas markets from the Gulf of Mexico to the eastern United States.

Shallow Water/ Onshore Gathering. Discovery also owns shallow water and onshore gathering assets that consist of:

- 90 miles of offshore laterals with pipeline diameters ranging from 12 inches to 20 inches with connections to the mainline. These shallow water laterals are located in water depths ranging from approximately 50 to 360 feet. Of the 90 miles of shallow water laterals, 60 miles are regulated by FERC;

- a fixed-leg shelf production handling facility installed along the mainline at Grand Isle 115. The platform facility allows for the injection of condensate into the pipeline and is equipped with a production handling facility; and

- a five-mile onshore gathering lateral with 20-inch diameter pipe that extends from a production area north of the Larose gas processing plant directly to the plant. This lateral is not regulated by FERC.

A Chevron-owned gathering system also connects to the Larose gas processing plant.

Deepwater Gathering. Discovery s deepwater gathering assets, which are located in water depths of greater than 1,000 feet, consist of 73 miles of gathering laterals, with pipeline diameters ranging from eight inches to 16 inches that extend to deepwater producing areas in the Gulf of Mexico such as the Morpeth prospect, Allegheny prospect and Front Runner prospect. The maximum water depth of these deepwater laterals is approximately 3,200 feet. Additionally, Discovery recently signed definitive agreements to construct a gathering pipeline lateral to connect Discovery s existing pipeline system to certain producers production facilities for the Tahiti prospect described above. None of Discovery s deepwater laterals are regulated by FERC.

Larose Gas Processing Plant

Discovery s cryogenic gas processing plant is located near Larose, Louisiana at the onshore terminus of Discovery s natural gas pipeline and has a design capacity of approximately 600 MMcf/d. The plant was placed in service in January 1998 and is located on land that Discovery leases from a third party. The initial term of the lease is 20 years and is renewable for ten-year intervals thereafter at Discovery s option for up to a total of 50 years.

We believe that the Larose plant is one of the most efficient and flexible gas processing plants in south Louisiana. The Larose plant is able to recover over 90 percent of the ethane contained in the natural gas stream and effectively 100 percent of the propane and heavier liquids. In addition, the processing plant is able to reject ethane down to effectively zero percent when justified by market economics, while retaining a propane recovery rate of over 95 percent and butanes and heavier liquids recovery rates of effectively 100 percent. We believe that the Larose plant consumes very low amounts of natural gas as fuel, using only approximately 1.4 percent of the volume of natural gas processed.

In addition to its gas processing activities, the Larose plant generates additional revenues by charging separate fees for ancillary services, such as dehydration and condensate separation and stabilization. Producers may also contract with Discovery for transportation of condensate from offshore production handling facilities and upon separation and stabilization, through Discovery s ten-mile condensate pipeline to a third party s oil gathering facility. Discovery also provides compression services for a third party s onshore gathering system that connects to Discovery s onshore lateral.

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Paradis Fractionation Facility

The fractionator is located onshore near Paradis, Louisiana. The fractionator and mixed NGL pipeline went into service in January 1998. The initial term of the lease is 20 years and is renewable for ten-year intervals thereafter at Discovery s option for up to a total of 50 years. The Paradis fractionator is designed to fractionate 32,000 bpd of mixed NGLs and is expandable to 42,000 bpd. In 2005, Discovery fractionated an average of approximately 9,600 bpd of mixed NGLs. All products can be delivered through the Chevron TENDS NGL pipeline system and propane and heavier products may be transported by truck or railway.

Discovery fractionates NGLs for third party customers and for itself, and typically it receives title to approximately one-half of the mixed NGL volumes leaving the Larose plant. A subsidiary of Williams markets substantially all of the NGLs and excess natural gas to which Discovery takes title by purchasing them from Discovery and reselling them to end-users. Discovery fractionates third party NGL volumes for a fractionation fee, which typically includes a base fractionation fee per gallon, that is subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs on a monthly basis and labor costs on an annual basis, which are the principal variable costs in NGL fractionation. As a result, Discovery is generally able to pass through increases in those fractionation expenses to its customers.

Discovery Management

Currently, Discovery is owned 40 percent by us, 20 percent by Williams and 40 percent by Duke Energy Field Services. Discovery is managed by a three member management committee consisting of representation from each of the three owners. The members of the management committee have voting power that corresponds to the ownership interest of the owner they represent. However, except under limited circumstances, all actions and decisions relating to Discovery require the unanimous approval of the owners. Discovery must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of such distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an area of interest.

Discovery Customers and Contracts

Customers. Discovery s customers are primarily offshore natural gas producers. Discovery provides these customers with wellhead to market delivery options by offering a full range of services including gathering, transportation, processing and fractionation. Discovery also has the ability to provide its customers with other specialized services, such as offshore production handling, condensate separation and stabilization and dehydration. Five offshore producer customers accounted for approximately 21 percent of Discovery s revenues in 2005. No customer accounted for over 10% of Discovery s revenues in 2005. Additionally, a subsidiary of Williams, which markets substantially all of the NGLs and excess natural gas to which Discovery takes title, accounted for approximately 57.7 percent of Discovery s revenues in 2005 even though it does not produce any of the natural gas that is supplied to Discovery.

Contracts. Discovery provides a complete range of wellhead to market services for its customers who are offshore producers in the Gulf of Mexico. The principal services provided include gathering, transportation, processing and fractionation. Discovery also provides ancillary services such as dehydration and condensate transportation, separation and stabilization. Each of these services is usually supported by a separate customer contract.

The mainline and the FERC-regulated laterals generate revenues through FERC-regulated tariffs for several types of service firm transportation service on a commodity basis with reserve dedication, firm transportation service on a commodity basis without reserve dedication to accommodate temporary outages due to Hurricane Katrina and traditional interruptible transportation service. Discovery also offers another type of service, traditional firm service with reservation fees, but none of Discovery s customers currently contracts for this transportation service. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Our Operations Gathering and Processing Segment.

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Discovery s maximum regulated rate for mainline transportation is scheduled to decrease in 2008. At that time, Discovery may be required to reduce its mainline transportation rate on all of its contracts that have rates above the new reduced rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with FERC to alter this scheduled reduction. However, if filed, we cannot assure you that a rate case would be successful in even partially preventing the scheduled rate reduction. Please read FERC Regulation.

Discovery s portfolio of processing contracts includes the following types of contracts:

Fee-based. Under fee-based contracts, Discovery receives revenue based on the volume of natural gas processed and the per-unit fee charged.

Percent-of-liquids. Under percent-of-liquids gas processing contracts, Discovery (1) processes natural gas for customers, (2) delivers to customers an agreed upon percentage of the NGLs extracted in processing and (3) retains a portion of the extracted NGLs. Discovery generates revenue from the sale of these retained NGLs to third parties at market prices. Some of Discovery s percent-of-liquids contracts have a bypass option. Under contracts with a bypass option, if customers elect not to process their natural gas due to unfavorable processing economics, Discovery retains a portion of the customers natural gas in lieu of NGLs as a fee. Discovery may choose to process gas that a customer has elected to bypass, but then must deliver natural gas with an equivalent Btu content to the customer.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Our Operations Gathering and Processing Segment Processing and Fractionation Contracts for additional information on Discovery s contracts.

Competition

The Discovery pipeline system competes with other wellhead to market delivery options available to offshore producers in the Gulf of Mexico. While Discovery offers integrated gathering, transportation, processing and fractionation services through a single provider, it generally competes with other offshore Gulf of Mexico gathering systems and interconnecting gas processing and fractionation facilities, some of which may have the same owner. On the continental shelf in shallow water, Discovery s pipeline system competes primarily with the MantaRay/ Nautilus system, the Trunkline system, the Tennessee System and the Venice Gathering System. These competing shallow water gathering systems connect to the following gas processing and fractionation facilities: the MantaRay/ Nautilus System connects to the Neptune gas processing plant, the Trunkline pipeline connects to the Patterson and Calumet gas processing plants, the Tennessee pipeline connects to the Yscloskey gas processing plant, and the Venice Gathering System connects to the Venice gas processing plant. In the deepwater region of the Gulf of Mexico, the Discovery pipeline system competes primarily with the Enterprise pipeline and the Cleopatra pipeline. The Enterprise pipeline connects to the ANR/ Pelican gas processing plant near Patterson, Louisiana, and the Cleopatra pipeline connects to the Neptune plant in Centerville, Louisiana.

Gas Supply

Approximately 60 offshore production blocks are currently dedicated to the Discovery system. Recently connected blocks include Murphy s Front Runner discovery, Energy Partners Rock Creek discovery, and Apache s Tarantula discovery. Additionally, Discovery recently signed definitive agreements with certain producers to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect described above. Furthermore, in areas that we believe are accessible to the Discovery pipeline system, approximately 600 deepwater blocks are currently leased and approximately 100 have related exploration plans filed with the Minerals Management Service of the U.S. Department of the Interior, or the MMS, or are named prospects. A named prospect is an individual lease or group of adjacent leases that are generally considered by a producer to have some economic potential for production.

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Gathering and Processing The Carbonate Trend Pipeline

General

Our Carbonate Trend gathering pipeline is a sour gas gathering pipeline consisting of approximately 34 miles of 12-inch diameter pipe that is used to gather sour gas production from the Carbonate Trend area off the coast of Alabama. Our Carbonate Trend pipeline is not regulated under the Natural Gas Act but is regulated under the Outer Continental Shelf Lands Act, which requires us to transport gas supplies on the Outer Continental Shelf on an open and non-discriminatory access basis. Sour gas is natural gas that has relatively high concentrations of acidic gases such as hydrogen sulfide and carbon dioxide. Our pipeline is designed to transport gas with a hydrogen sulfide and carbon dioxide content that exceeds normal gas transportation specifications. The pipeline was built and placed in service in 2000 and has a maximum design throughput capacity of approximately 120 MMcf/d. For the year ended December 31, 2005, our average transportation volume was approximately 35 MMcf/d.

Gas is shipped through our pipeline to Shell s offshore sour gas gathering pipeline and Yellowhammer sour gas treating facility located onshore in Coden, Alabama. From the Yellowhammer facility, treated gas can be delivered to the Williams-owned Mobile Bay gas processing plant, which has multiple pipeline interconnections to Transco, Florida Gas Transmission, Gulfstream, Mobile Gas Services and GulfSouth pipelines. Treated gas may also be delivered directly into the GulfSouth or the Transco pipelines at the tailgate of the Yellowhammer facility without processing.

Our pipeline extends from Chevron s production platform located at Viosca Knoll Block 251 to an interconnection point with Shell s offshore sour gas gathering facility located at Mobile Bay Block 113. The pipeline is operated by Chevron under an operating agreement. We contract with Williams for the formulation of a corrosion control program to ensure the maintenance and reliability of our pipeline. Due to the corrosive nature of the sour gas, Williams has formulated and Chevron has implemented a corrosion control program for the Carbonate Trend pipeline. Please read Safety and Maintenance.

Revenue from the Carbonate Trend pipeline is generated through negotiated fees that we charge our customers to transport gas to the Shell offshore sour gas gathering system. These fees typically depend on the volume of gas we transport.

Carbonate Trend Customers and Contracts

Customers. Our primary customer on the Carbonate Trend pipeline is Chevron, which, together with Noble Energy, has large lease positions in the Carbonate Trend area. Chevron and Noble Energy own an interest in more than 30 federal leases in the Carbonate Trend area and Chevron is the operator for the majority of these leases. For the year ended December 31, 2005, volumes from these Chevron leases represented approximately 67 percent of Carbonate Trend s total throughput and 74 percent of Carbonate Trend s total revenue with volumes from Noble Energy constituting the remainder.

Contracts. We have long-term transportation agreements with Chevron and Noble Energy. Pursuant to these agreements, Chevron and Noble Energy have agreed to transport on our pipeline all gas produced on their 27 Carbonate Trend leases for the life of the leases or the economic life of the underlying reserves. There is no minimum volume requirement, and if the leases held by Chevron and Noble Energy expire or the underlying reserves are depleted, Chevron and Noble Energy will not be committed to ship any natural gas on our pipeline. In addition, if any lease expires, and is reacquired by the same company within ten years of such expiration, all production from that lease must again be transported via our pipeline. Under these agreements Chevron and Noble Energy may make an annual election to utilize capacity along a segment of Transco. When Chevron or Noble Energy utilize this capacity, our per-unit gathering fee is determined by subtracting the FERC tariff-based rate charged by Transco for this capacity from the total negotiated fee. If these customers elect not to utilize the capacity along this segment of Transco, we can make no assurance that this capacity will be made available to these customers in the future. We have the option to terminate these agreements if expenses exceed certain levels or if revenues fall below certain levels and we are not compensated for these expenses or shortfalls.

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Competition

Other than the producer gathering lines that connect to the Carbonate Trend pipeline, there are no other sour gas gathering and transportation pipelines in the Carbonate Trend area, and we know of no current plans to build competing pipelines. As a result, as other blocks in the Carbonate Trend are developed, we believe that producers will find it more cost effective to connect to our pipeline than to construct or commission new sour gas pipelines of their own.

Gas Supply

Chevron developed the Viosca Knoll Carbonate Trend area in the shallow waters of the Mobile and Viosca Knoll areas in the eastern Gulf of Mexico. Chevron has filed several exploration plans with the MMS that we believe could result in the discovery of additional amounts of natural gas. Other producers may also transport gas on the Carbonate Trend pipeline. If the Yellowhammer facility becomes unavailable for the treatment of our customers sour gas, we believe that we can construct pipeline connections to access either of two third party-owned treating facilities also located in Coden, Alabama.

NGL Services The Conway Assets

General

Our Conway assets are strategically located at one of the two major NGL trading hubs in the continental United States and consist of:

- three integrated NGL storage facilities; and
- a 50 percent interest in an NGL fractionator.

Conway Storage Assets

General. We believe we are the largest NGL storage facility, in terms of capacity, in the Mid-Continent Region. We own and operate three integrated underground NGL storage facilities in the Conway, Kansas area with an aggregate capacity of approximately 20 million barrels, which we refer to as the Conway West, Conway East and Mitchell storage facilities. Each facility is comprised of a network of caverns located several hundred feet below ground, and all three facilities are connected by pipeline. The caverns hold large volumes of NGLs and other hydrocarbons, such as propylene and naphtha. We operate these assets as one coordinated facility. Three lines connect the Mitchell facility to the Conway West facility and two lines connect the Conway East facility to the Conway West Facility. These facilities have a total brine pond capacity of approximately 13 million barrels.

Our Conway storage facilities interconnect directly with two end-use interstate NGL pipelines: MAPL and the Kinder Morgan pipeline. We also, through connections of less than a mile, indirectly interconnect to two additional end-use interstate NGL pipelines: the Kaneb pipeline and the ONEOK pipeline. Through these pipelines and other storage facilities we can provide our customers interconnectivity to additional interstate NGL pipelines. We believe that the attributes of our storage facilities, such as the number and size of our caverns and well bores and our extensive brine system, coupled with our direct connectivity to MAPL through multiple meters allows our customers to inject, withdraw and deliver all of their products stored in our facilities more rapidly than products stored with our competitors.

Conway West. The Conway West facility located adjacent to the Conway fractionation facility in McPherson County, Kansas is our primary storage facility. This facility has an aggregate storage capacity of approximately ten million barrels.

Conway East. The Conway East facility is located approximately four miles east of the Conway West facility in McPherson County, Kansas. The Conway East facility has an aggregate storage capacity of approximately five million barrels. The Conway East facility also has an active truck loading and unloading facility, each with two spots, and a rail loading and unloading facility with 20 spots.

Mitchell. The Mitchell facility is located approximately 14 miles west of the Conway West facility in Rice County, Kansas and has an aggregate storage capacity of approximately five million barrels.

Customers and Contracts

Customers. Our NGL storage customers include NGL producers, NGL pipeline operators, NGL service providers and NGL end-users. Our three largest customers, which accounted for 65 percent of our storage revenues in 2005, are SemStream, Enterprise and ONEOK. Enterprise is an NGL pipeline operator, ONEOK is an NGL service provider, while SemStream is principally involved in propane marketing and distribution.

Contracts. Our storage year for customer contracts runs from April 1 to March 31. We lease capacity on varying terms from less than six months to a year or more and have additional capacity available to contract. Our storage revenues are not generally affected by seasonality because our customers generally pay for storage capacity, not injected or withdrawn volumes.

We have long-term contracts with SemStream, Enterprise and ONEOK. These three customers contract for approximately seven million barrels of storage capacity per year for terms that expire between 2009 and 2018. Each of these contracts is based on a percentage of our published price of storage in our Conway facilities, which we adjust annually.

Aside from our long-term contracts, most of our contracts are for a period of one year. In addition, we also enter into contracts for fungible product storage in increments of six months, three months or one month. For contracts of one year or less, our customers are required to remit the full contract price at the time the contract is signed, which makes us less susceptible to credit risks. One of our customers is the beneficiary of an agreement, which terminates in 2019, that provides this customer with a yearly $177,000 credit against storage fees that it may incur in excess of the fees that it incurs for its contracted storage.

We currently offer our customers four types of storage contracts single product fungible, two product fungible, multi-product fungible and segregated product storage in various quantities and at varying terms. Single product fungible storage allows customers to store a single product. Two-product fungible storage allows customers to store any combination of two fungible products. Multi-product fungible storage allows customers to store any combination of fungible products. In the case of two-product and multi-product storage, the customer designates the quantity of storage space for each product at the beginning of the lease period. Customers may change their quantity configurations throughout the year based upon our ability to accommodate each change. Segregated storage also is available to customers who desire to store non-fungible products at Conway, such as propylene, refinery grade butane and naphtha. We evaluate pricing, volume and availability for segregated storage on a case-by-case basis. Segregated storage allows a customer to lease an entire storage cavern and have its own product injected and withdrawn without having its product commingled with the products of our other customers. In addition to the fees we charge for fungible product storage and segregated product storage, we also receive fees for overstorage.

Competition

We compete with other salt cavern storage facilities. Our most direct competitor is a ONEOK-owned Bushton, Kansas storage facility that is directly connected to a Kinder Morgan pipeline. Other competitors include a ONEOK-owned facility in Conway, Kansas, a NCRA-owned facility in Conway, Kansas, a ONEOK-owned facility in Hutchinson, Kansas and an Enterprise Products Partners-owned facility in Hutchinson, Kansas. We also compete with storage facilities on the Gulf Coast and in Canada to the extent that NGL product commodity prices differ between the Mid-Continent region and those areas and interstate pipelines to the extent that they offer storage services.

An increase in competition in the market could arise from new ventures or expanded operations from existing competitors. Other competitive factors include (1) the quantity, location and physical flow characteristics of interconnected pipelines, (2) the ability to offer service from multiple storage locations,

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(3) the costs of service and rates of our competitors and (4) NGL product commodity prices in the Mid-Continent region as compared to prices in other regions.

NGL Sources and Transportation Options

We generally receive the NGLs that we inject into our facilities, and our customers generally choose to transport the NGLs that we withdraw from our facilities, through the interstate NGL pipelines that interconnect with our storage facilities, including MAPL, a Kinder Morgan pipeline, a Kaneb pipeline and a ONEOK pipeline. We also receive substantially all of the separated NGLs from our fractionator for storage and further transportation through these interstate pipelines.

Additionally, our customers have the option to have NGLs delivered to or transported from our storage facility, through our active truck loading and unloading facility, each with two spots, or our rail loading and unloading facility with 20 spots.

The Conway Fractionation Facility

General. The Conway fractionation facility is strategically located at the junction of the south, east and west legs of MAPL and has interconnections with the BP Wattenberg pipeline and the ConocoPhillips Chisholm pipeline, each of which transports mixed NGLs to our facility. The Conway fractionation facility began operations in 1973 with a single production train. In 1977, a second train was added and the capacity of the first train was upgraded, which brought the total design capacity of the Conway fractionation facility to approximately 107,000 bpd.

We own a 50 percent undivided interest in the Conway fractionation facility, representing capacity of approximately 53,500 bpd. ConocoPhillips owns a 40 percent undivided interest, representing capacity of approximately 42,800 bpd, and ONEOK owns a 10 percent undivided interest, representing capacity of approximately 10,700 bpd. Each joint owner markets its own capacity independently. Each owner can also contract with the other owners for additional capacity at the Conway fractionation facility, if necessary. We are the operator of the facility pursuant to an operating agreement that extends until May 2011.

We primarily fractionate NGLs for third party customers for a fee based on the volumes of mixed NGLs fractionated. The per-unit fee we charge is generally subject to adjustment for changes in certain fractionation expenses, including natural gas, electricity and labor costs, which are the principal variable costs in NGL fractionation. As a result, we are generally able to pass through increases in those fractionation expenses to our customers. However, under one of our long-term fractionation contracts described below, there is a cap on the per-unit fee and, under current natural gas market conditions, we are not able to pass through the full amount of increases in variable expenses to this customer. In order to mitigate the fuel price risk with respect to our purchases of natural gas needed to perform under this contract, upon the closing of our initial public offering, Williams transferred to us a contract for the purchase of a sufficient quantity of natural gas from a wholly owned subsidiary of Williams at a price not to exceed a specified price to satisfy our fuel requirements under this fractionation contract. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Our Operations NGL Services Segment Fractionation Contracts.

The results of operations of the Conway fractionation facility are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. Overall, the NGL fractionation business exhibits little to no seasonal variation as NGL production is relatively constant throughout the year. We have capacity available at our fractionation facility to accommodate additional volumes.

Customers and Contracts

Customers. We have long-term fractionation agreements with BP and Enterprise, which together accounted for approximately 64 percent of our NGL fractionation capacity at the Conway facility for the year ended December 31, 2005. Our other fractionation customers include Duke and Coffeyville Resources.

Contracts. We have a long-term contract with BP which requires BP to deliver all of its proprietary mixed NGLs from its Wattenberg pipeline, which runs from eastern Colorado to Bushton, Kansas, and its

Hugoton, Kansas gas processing plant to the Conway fractionator. There is no minimum volume requirement, however, and if BP s Hugoton processing plant and the Wattenberg pipeline were to cease operations for any reason, BP would not be required to deliver any mixed NGLs for fractionation under this agreement. BP accounted for approximately 13.5 percent, 16.1 percent and 24.6 percent of our total revenue in 2005, 2004 and 2003 respectively. The term of the agreement with respect to deliveries from the Wattenberg pipeline expires on January 1, 2008 but will automatically be renewed on a year-to-year basis unless otherwise terminated by the parties. The term of the agreement with respect to deliveries from Hugoton expires on January 1, 2013 and may be terminated effective January 1, 2008 if either party provides notice of termination before December 31, 2005. Pursuant to the terms of this agreement, we provided notice of termination to BP in July 2005.

Another long-term contract requires a customer to deliver all of the mixed NGLs that customer purchases from Pioneer s Texas Panhandle and southwestern Kansas natural gas processing facilities to the Conway fractionator if it chooses to ship its mixed NGLs to the Mid-Continent region, as defined in the agreement. However, if the customer chooses to ship its mixed NGLs to another region, it has the right, on a month-to-month basis, to deliver its mixed NGLs elsewhere. The customer s decision on whether to ship its products to the Mid-Continent region or to another region depends on factors including supply and demand in the respective regions and the current price being paid for fractionated products in each region. Deliveries of mixed NGL products under this agreement have remained consistent during the term of this agreement. This agreement expires in 2009.

We generally enter into contracts that cover a portion of our remaining capacity at the Conway facility for periods of one year or less.

Competition

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products are also important competitive factors and are determined by the existence of the necessary pipeline and storage infrastructure. NGL fractionators connected to extensive storage, transportation and distribution systems such as ours have direct access to larger markets than those with less extensive connections. Our principal competitors are a ONEOK-owned fractionator located in Medford, Oklahoma, a ONEOK-owned fractionator located in Hutchinson, Kansas and a ONEOK-owned fractionator located in Bushton, Kansas. We compete with the two other joint owners of the Conway fractionation facility for third party customers. We also compete with fractionation facilities on the Gulf Coast, to the extent that NGL product commodity prices differ between the Mid-Continent region and the Gulf Coast.

An increase in competition in the market could arise from new ventures or expanded operations from existing competitors. Other competitive factors include (1) the quantity and location of interconnected pipelines, (2) the costs and rates of our competitors, (3) whether fractionation providers offer to purchase a customers mixed NGLs instead of providing fee based fractionation services and (4) NGL product commodity prices in the Mid-Continent region as compared to prices in other regions.

Mixed NGL Sources

Based on EIA projections of relatively stable production levels of natural gas in the Mid-Continent region over the next ten years, we believe that sufficient volumes of mixed NGLs will be available for fractionation in the foreseeable future. In addition, through connections with MAPL and the BP Wattenberg pipeline, the Conway fractionation facility has access to mixed NGLs from additional major supply basins in North America, including additional major supply basins in the Rocky Mountain production area.

NGL Transportation Options

After the mixed NGLs are separated at the fractionator, the NGL products are typically transported to our storage facilities. At our storage facilities, the NGLs may be stored or transported on one of the interconnected NGL pipelines. Our customers also have the option to have their NGL products transported

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through our truck loading and rail loading facilities. Additionally, when market conditions dictate, we have the ability to place propane directly into MAPL from our fractionator, providing our customers with expedited access to interstate markets.

Safety and Maintenance

Discovery s natural gas pipeline system is subject to regulation by the United States Department of Transportation, referred to as DOT, under the Accountable Pipeline and Safety Partnership Act of 1996, referred to as the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations.

Discovery s gas pipeline system is also subject to the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Improvement Act of 2002. The Natural Gas Pipeline Safety Act regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within ten years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We currently estimate we will incur costs of approximately $1.7 million between 2006 and 2008 to implement integrity management program testing along certain segments of Discovery s 16, 20, and 30-inch diameter natural gas pipelines and its 10, 14, and 18-inch diameter NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate.

Our natural gas pipelines have continuous inspection and compliance programs designed to keep its facilities in compliance with pipeline safety and pollution control requirements. In compliance with applicable permit requirements, we completed a survey of portions of our Carbonate Trend pipeline. As a result of this survey, we have determined that it will be necessary for us to undertake certain restoration activities to repair the partial erosion of the pipeline overburden caused by Hurricane Ivan in September 2004. We estimate that the cost of these restoration activities will be between $3.4 and $4.6 million and that they will be completed by the end of 2006. In the omnibus agreement, Williams agreed to reimburse us for the cost of these restoration activities. We believe that our natural gas pipelines are in material compliance with the applicable requirements of these safety regulations.

Our Carbonate Trend pipeline requires a corrosion control program to protect the integrity of the pipeline and prolong its life. The corrosion control program consists of continuous monitoring and injection of corrosion inhibitor into the pipeline, periodic chemical treatments and annual detailed comprehensive inspections. We believe that this is an aggressive and proactive corrosion control program that will reduce metal loss, limit corrosion and possibly extend the service life of the pipe by 15 to 20 years.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, referred to as OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that informa-

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tion be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with the OSHA regulations.

FERC Regulation

General

The Carbonate Trend sour gas gathering pipeline and the offshore portion of Discovery s natural gas pipeline are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico.

Portions of Discovery s natural gas pipeline are also subject to regulation by FERC, under the Natural Gas Act. The Natural Gas Act requires, among other things, that the rates be just and reasonable and nondiscriminatory. Under the Natural Gas Act, FERC has authority over the construction, operation and expansion of interstate pipeline facilities, as well as the terms and conditions of service provided by the operator of such facilities. In general, Discovery must receive prior FERC approval to construct, operate or expand its FERC-regulated facilities, to initiate new service using such facilities, to alter the terms and conditions of service provided on such facilities, and to abandon service provided by its FERC-regulated facilities. With respect to certain types of construction activities and certain types of service, FERC has issued rules that allow regulated pipelines to obtain blanket authorizations that obviate the need for prior specific FERC approvals for initiating and abandoning service. Commencing in 1992, FERC issued a series of orders (Order No. 636), which require interstate pipelines to provide transportation service separate or unbundled from the pipelines sales of gas. Order No. 636 also required interstate pipelines, such as Discovery to provide open access transportation on a non-discriminatory basis that is equal for all similarly situated shippers. The Natural Gas Act also gives FERC the authority to regulate the rates that Discovery charges for service on portions of its natural gas pipeline system. The natural gas pipeline industry has historically been heavily regulated by federal and state governments, and we cannot predict what further actions FERC, state regulators, or federal and state legislators may take in the future.

The Discovery 105-mile mainline, approximately 60 miles of laterals and its market expansion project are subject to regulation by FERC. The following table shows the maximum transportation tariffs that Discovery can charge on its regulated transportation pipelines:

Discovery Asset	Maximum FERC Rate
Mainline	\$0.1569/MMBtu through January 2008; \$0.08 thereafter
FERC-regulated laterals	\$0.039/MMBtu
Market expansion project	\$0.08/MMBtu

Under Discovery s current FERC-approved tariff, the maximum rate that Discovery may charge its customers for the transportation of natural gas along its mainline is \$0.1569/ MMBtu. This maximum rate is scheduled to decrease in 2008 to \$0.08/ MMBtu. At that time, Discovery may be required to reduce its mainline transportation rate on all of its contracts that have rates above the new maximum rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with FERC seeking to alter this scheduled reduction.

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However, if filed, we cannot assure you that a rate case would be successful in even partially preventing the scheduled rate reduction.

In connection with a rate case filed by Discovery, all aspects of its cost of service and rate design of its rates could be reviewed, including the following:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the rate;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity;
- the cost of debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

In a decision issued in July 2004 involving an oil pipeline limited partnership, *BP West Coast Products, LLC v. FERC*, the United States Court of Appeals for the District of Columbia Circuit upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, SFPP, L.P., or SFPP, were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC s decision applying the *Lakehead* policy. In its *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which it stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income allowance. The FERC s *BP West Coast* remand decision and the new tax allowance policy have been appealed to the D.C. Circuit, and rehearing requests have been filed with respect to the December 2005 order. Therefore, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service. If FERC were to disallow a substantial portion of Discovery s income tax allowance, it may be more difficult for Discovery to justify its rates.

These aspects of Discovery s rates also could be reviewed if FERC or a shipper initiated a complaint proceeding. However, we do not believe that it is likely that there will be a challenge to Discovery s rates by a current shipper that would materially affect its revenues or cash flows.

In 2000, FERC issued Order No. 637 which, among other things:

- required pipelines to implement imbalance management services;
- restricted the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and

implemented a number of new pipeline reporting requirements.

In addition, FERC implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement, which it largely affirmed in a recent order on rehearing, establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates based solely on the costs associated with such new pipeline facilities. We cannot predict what further action FERC will take on these matters. However, we do not believe that Discovery will be affected by any action taken previously or in the future on these matters materially differently than other natural gas gatherers and processors with which it competes.

Commencing in 2003, FERC issued a series of orders adopting rules for new Standards of Conduct for Transmission Providers (Order No. 2004) which apply to interstate natural gas pipelines such as Discovery. Order No. 2004 became effective in 2004. Among other matters, Order No. 2004 requires interstate pipelines to operate independently from their energy affiliates, prohibits interstate pipelines from providing non-public transportation or shipper information to their energy affiliates; prohibits interstate pipelines from favoring their energy affiliates in providing service; and obligates interstate pipelines to post on their websites a number of items of information concerning the pipeline, including its organizational structure, facilities shared with energy affiliates, discounts given for transportation service, and instances in which the pipeline has agreed to waive discretionary terms of its tariff. Discovery requested and received a partial waiver from certain portions of Order No. 2004. Since the effective date of Order No. 2004, Discovery has determined that additional waivers from compliance with Order No. 2004 are necessary to accommodate the management committee structure under which Discovery operates. Discovery filed for additional limited waivers from Order No. 2004 compliance on May 6, 2005 requesting a limited waiver to permit three Duke Energy Field Services (DEFS) employees to be shared between Discovery and DEFS and to provide information necessary for DEFS to carry out its responsibilities as an owner of Discovery. FERC has not yet acted on this filing.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot assure you that the less stringent and pro-competition regulatory approach recently pursued by FERC and Congress will continue.

The Carbonate Trend pipeline is a gathering pipeline, and is not subject to FERC jurisdiction under the Natural Gas Act.

Processing Plant

The primary function of Discovery s natural gas processing plant is the extraction of NGLs and the conditioning of natural gas for marketing into the natural gas pipeline grid. FERC has traditionally maintained that a processing plant that primarily extracts NGLs is not a facility for transportation or sale of natural gas for resale in interstate commerce and therefore is not subject to its jurisdiction under the Natural Gas Act. We believe that the natural gas processing plant is primarily involved in removing NGLs and, therefore, is exempt from the jurisdiction of FERC.

Environmental Regulation

General

Our operation of pipelines, plants and other facilities for gathering, transporting, processing or storing natural gas, NGLs and other products is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment. Due to the myriad of complex federal, state and local laws and regulations that may affect us, directly or indirectly, you should not rely on the following discussion of certain laws and regulations as an exhaustive review of all regulatory considerations affecting our operations.

As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position in that the operations of our competitors are similarly affected. We believe that our operations are in material compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to frequent, and often times more stringent, change by regulatory authorities and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations and permits can result in the imposition of significant administrative, civil and criminal penalties, remedial obligations, injunctions and construction bans or delays. A discharge of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

We or the entities in which we own an interest inspect the pipelines regularly using equipment rented from third party suppliers. Third parties also assist us in interpreting the results of the inspections.

In the omnibus agreement executed in connection with our IPO, Williams agreed to indemnify us in an aggregate amount not to exceed $14.0 million, including any amounts recoverable under our insurance policy covering remediation costs and unknown claims at Conway, generally for three years after the closing of our initial public offering in August 2005, for certain environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before the closing date of our initial public offering.

Air Emissions

Our operations are subject to the Clean Air Act and comparable state and local statutes. Amendments to the Clean Air Act enacted in late 1990 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 U.S. Environmental Protection Agency, or 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 1990 Clean Air Act Amendments established a new operating permit for major sources. Although we can give no assurances, we believe that the expenditures needed for us to comply with the 1990 Clean Air Act Amendments will not have a material adverse effect on our financial condition or results of operations.

Hazardous Substances and Waste

To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water, and include measures to control pollution of the environment. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste. They also require corrective action, including the investigation and remediation of certain units, at a facility where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as CERCLA or 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 that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the petroleum exclusion of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

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We also generate solid wastes, including hazardous wastes, that are subject to the requirements of the federal Solid Waste Disposal Act, the federal Resource Conservation and Recovery Act, referred to as RCRA, and comparable state statutes. From time to time, the EPA considers the adoption of stricter disposal standards for wastes currently designated as non-hazardous. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and therefore subject to more rigorous and costly disposal requirements than non-hazardous wastes. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease, and our predecessor has in the past owned or leased, 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 or under the properties owned or leased by us or on or under other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain 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 CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act, also referred to as the CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water run-off. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water run-off. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Hazardous Materials Transportation Requirements

The DOT regulations affecting pipeline safety require pipeline operators to implement measures designed to reduce the environmental impact of discharge from onshore pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. In addition, the DOT regulations contain detailed specifications for pipeline operation and maintenance. We believe our operations are in substantial compliance with these regulations. Please read Safety and Maintenance.

Kansas Department of Health and Environment Obligations

We currently own and operate underground storage caverns near Conway, Kansas that have been created by solution mining the caverns in the Hutchinson salt formation. These storage caverns are used to store NGLs and other liquid hydrocarbons. These caverns are subject to strict environmental regulation by the Underground Storage Unit within the Bureau of Water, Geology Section of the KDHE under the Underground Hydrocarbon and Natural Gas Storage Program. The current revision of the Underground Hydrocarbon and Natural Gas Storage regulations became effective on April 1, 2003 (temporary) and August 8, 2003 (permanent); these rules regulate the storage of liquefied petroleum gas, hydrocarbons and natural gas in bedded salt for the purpose of protecting public health and safety, property and the environment and regulates the construction, operation and closure of brine ponds associated with our storage caverns. The regulations specify several compliance deadlines including the final permit application for existing hydrocarbon storage wells by April 1, 2006, certain equipment requirements no later than April 1, 2008 and mechanical integrity and casing testing requirements by April 1, 2010. Failure to comply with the Underground Hydrocarbon and Natural Gas Storage Program may lead to the assessment of administrative, civil or criminal penalties.

We are in the process of modifying our Conway storage facilities, including the caverns and brine ponds, and we believe that our storage operations will be in compliance with the Underground Hydrocarbon and Natural Gas Storage Program regulations by the applicable compliance dates. In 2003, we began to complete workovers on approximately 30 to 35 salt caverns per year and install, on average, a double liner on one brine pond per year. The incremental costs of these activities is approximately $5.5 million per year to complete the workovers and approximately $900,000 per year to install a double liner on a brine pond. In response to these increased costs, we raised our storage rates by an amount sufficient to preserve our margins in this business. Accordingly, we do not believe that these increased costs have had a material effect on our business or results of operations. We expect on average to complete workovers on each of our caverns every five to ten years and install double liners on each of our brine ponds every 18 years.

Furthermore, the KDHE has advised us that a regulation relating to the metering of NGL volumes that are injected and withdrawn from our caverns may be interpreted to require the installation of meters at each of our well bores. We have informed the KDHE that we disagree with this interpretation, and the KDHE has asked us to provide it with additional information. We have made a proposal to install individual cavern meters at 12 caverns that are connected to the fractionator and NGL pipelines. The estimated cost for this work is $220,000. If this proposal is not accepted, we estimate that the cost of installing a meter at each of our well bores at Conway West and Mitchell would be approximately $3.9 million over three years.

Additionally, we are currently undergoing remedial activities pursuant to KDHE Consent Orders issued in the early 1990s. The Consent Orders were issued after elevated concentrations of chlorides were discovered in various on-site and off-site shallow groundwater resources at each of our Conway storage facilities. With KDHE approval, we are currently installing and implementing a containment and monitoring system to delineate further the scope of and to arrest the continued migration of the chloride plume at the Mitchell facility. Investigation and delineation of chloride impacts is ongoing at the two Conway area facilities as specified in their respective consent orders. One of these facilities is located near the Groundwater Management District No. 2 s jurisdictional boundary of the Equus Beds aquifer. At the other Conway area facility, remediation of residual hydrocarbon derivatives from a historic pipeline release is included in the consent order required activities.

Although not mandated by any consent order, we are currently cooperating with the KDHE and other area operators in an investigation of fugitive NGLs observed in the subsurface at the Conway Underground East facility. In addition, we have also recently detected fugitive NGLs in groundwater monitoring wells adjacent to two abandoned storage caverns at the Conway West facility. Although the complete extent of the contamination appears to be limited and appears to have been arrested, we are continuing to work to delineate further the scope of the contamination. To date, the KDHE has not undertaken any enforcement action related to the releases around the abandoned storage caverns.

We are continuing to evaluate our assets to prevent future releases. While we maintain an extensive inspection and audit program designed, as appropriate, to prevent and to detect and address such releases promptly, there can be no assurance that future environmental releases from our assets will not have a material effect on us.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee, such as land at the Conway fractionation and storage facility, and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which major facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, right-of-way and licenses.

Employees

We do not have any employees. We are managed and operated by the directors and officers of our general partner. To carry out our operations, as of December 31, 2005, our general partner or its affiliates employed approximately 36 people who will spend at least a majority of their time operating the Conway and Carbonate Trend facilities and approximately 30 general and administrative full-time equivalent employees in support of these operations. Discovery is operated by Williams pursuant to an operating and maintenance agreement and the employees who operate the Discovery assets are therefore not included in the above numbers. For further information, please read Directors and Officers of the Registrant Reimbursement of Expenses of our General Partner and Certain Relationships and Related Transactions.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

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

Item 1A. ***Risk Factors***

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. The reader should carefully consider the following risk factors in addition to the other information in this annual report. If any of the following risks were actually to occur, our business, results of operations and financial condition could be materially adversely affected. In that case, we might not be able to pay distributions on our common units and the trading price of our common units could decline and unitholders could lose all or part of their investment.

Risks Inherent in Our Business

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

We may not have sufficient available cash each quarter to pay the minimum quarterly distribution. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the prices we obtain for our services;
- the prices of, level of production of, and demand for, natural gas and NGLs;
- the volumes of natural gas we gather, transport and process and the volumes of NGLs we fractionate and store;
- the level of our operating costs, including payments to our general partner; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors such as:

- the level of capital expenditures we make;
- the restrictions contained in our and Williams debt agreements and our debt service requirements;

- the cost of acquisitions, if any;
- fluctuations in our working capital needs;
- our ability to borrow for working capital or other purposes;
- the amount, if any, of cash reserves established by our general partner;
- the amount of cash that Discovery distributes to us; and
- reimbursement payments to us by, and credits from, Williams under the omnibus agreement.

Unitholders should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make cash distributions during periods when we record net income.

Because of the natural decline in production from existing wells, the success of our gathering and transportation businesses depends on our ability to obtain new sources of natural gas supply, which is dependent on factors beyond our control. Any decrease in supplies of natural gas could adversely affect our business and operating results.

Our and Discovery s pipelines receive natural gas directly from offshore producers. The production from existing wells connected to Discovery s pipelines will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. We do not produce an aggregate reserve report on a regular basis or regularly obtain or update independent reserve evaluations. The amount of natural gas reserves underlying these wells may be less than we anticipate, and the rate at which production will decline from these reserves may be greater than we anticipate. Accordingly, to maintain or increase throughput levels on these pipelines and the utilization rate of Discovery s natural gas processing plant and fractionator, we and Discovery must continually obtain new supplies of natural gas. The primary factors affecting our ability to obtain new supplies of natural gas and attract new customers to our pipelines include: (1) the level of successful drilling activity near these pipelines; (2) our ability to compete for volumes from successful new wells and (3) our and Discovery s ability to successfully complete lateral expansion projects to connect to new wells.

We have no current significant lateral expansion projects planned, and Discovery has only one currently planned significant lateral expansion project. Discovery recently signed definitive agreements with Chevron, Shell and Statoil to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. Initial production is expected in April 2008.

The level of drilling activity in the fields served by our and Discovery s pipelines is dependent on economic and business factors beyond our control. The primary factors that impact drilling decisions are oil and natural gas prices. A sustained decline in oil and natural gas prices could result in a decrease in exploration and development activities in these fields, which would lead to reduced throughput levels on our pipelines. Other factors that impact production decisions include producers capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if new oil or natural gas reserves are discovered in areas served by our pipelines, producers may choose not to develop those reserves. If we were not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, due to reductions in drilling activity, competition, or difficulties in completing lateral expansion projects to connect to new supplies of natural gas, throughput on our pipelines and the utilization rates of Discovery s natural gas processing plant and fractionator would decline, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Lower natural gas and oil prices could adversely affect our fractionation and storage businesses.

Lower natural gas and oil prices could result in a decline in the production of natural gas and NGLs resulting in reduced throughput on our pipelines. Any such decline would reduce the amount of NGLs we fractionate and store, which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to unitholders.

In general terms, the prices of natural gas, NGLs and other hydrocarbon products fluctuate in response to changes in supply, changes in demand, market uncertainty and a variety of additional factors that are impossible to control. These factors include:

- worldwide economic conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported natural gas and NGLs;
- the availability of transportation systems with adequate capacity;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of natural gas, NGLs and other commodities.

Our processing, fractionation and storage businesses could be affected by any decrease in NGL prices or a change in NGL prices relative to the price of natural gas.

Lower NGL prices would reduce the revenues we generate from the sale of NGLs for our own account. Under certain gas processing contracts, referred to as percent-of-liquids contracts, Discovery receives NGLs removed from the natural gas stream during processing. Discovery can then choose to either fractionate and sell the NGLs or to sell the NGLs directly. In addition, product optimization at our Conway fractionator generally leaves us with excess propane, an NGL, which we sell. We also sell excess storage volumes resulting from measurement variances at our Conway storage facilities.

The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for Discovery and its customers to process natural gas. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas both because of the higher value of natural gas and of the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, Discovery may experience periods in which higher natural gas prices reduce the volumes of natural gas processed at its Larose plant, which would reduce its gross processing margins. Finally, higher natural gas prices relative to NGL prices could also reduce volumes of gas processed generally, reducing the volumes of mixed NGLs available for fractionation.

We depend on certain key customers and producers for a significant portion of our revenues and supply of natural gas and NGLs. The loss of any of these key customers or producers could result in a decline in our revenues and cash available to pay distributions.

We rely on a limited number of customers for a significant portion of our revenues. Our three largest customers for the year ended December 31, 2005, other than a subsidiary of Williams that markets NGLs for Conway, were BP Products North America, Inc., SemStream, L.P. and Enterprise Products Partners, all customers of our Conway facilities. These customers accounted for approximately 45 percent of our revenues for the year ended December 31, 2005.

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In addition, although some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts, on favorable terms, if at all. The loss of all or even a portion of the volumes of natural gas or NGLs, as applicable, supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to unitholders, unless we are able to acquire comparable volumes from other sources.

If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport natural gas and NGLs or to treat natural gas, our revenues and cash available to pay distributions could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. For example, MAPL delivers its customers mixed NGLs to our Conway fractionator and provides access to multiple end markets for the NGL products of our storage customers. If MAPL were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines, reduced operating pressures, lack of capacity or other causes, our customers would be unable to store or deliver NGL products and we would be unable to receive deliveries of mixed NGLs at our Conway fractionator. This would have an immediate adverse impact on our ability to enter into short-term storage contracts and our ability to fractionate sufficient volumes of mixed NGLs at Conway.

As another example, Shell s Yellowhammer sour gas treating facility in Coden, Alabama is the only sour gas treating facility currently connected to our Carbonate Trend pipeline. Natural gas produced from the Carbonate Trend area must pass through a Shell-owned pipeline and Shell s Yellowhammer sour gas treating facility before delivery to end markets. If the Shell-owned pipeline or the Yellowhammer facility were to become unavailable for current or future volumes of natural gas delivered to it through the Carbonate Trend pipeline due to repairs, damages to the facility, lack of capacity or any other reason, our Carbonate Trend customers would be unable to continue shipping natural gas to end markets. Since we generally receive revenues for volumes shipped on the Carbonate Trend pipeline, this would reduce our revenues.

Any temporary or permanent interruption in operations at MAPL, Yellowhammer or any other third party pipelines or facilities that would cause a material reduction in volumes transported on our pipelines or processed, fractionated, treated or stored at our facilities could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to unitholders.

Williams revolving credit facility and Williams public indentures contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

We have the ability to incur up to $75 million of indebtedness under Williams $1.275 billion revolving credit facility. However, this $75 million of borrowing capacity will only be available to us to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. As a result, borrowings by Williams could restrict our access to credit. As of December 31, 2005, letters of credit totaling $378 million had been issued on behalf of Williams by the participating institutions under the facility and we did not have any revolving credit loans outstanding. In addition, Williams public indentures contain covenants that restrict Williams and our ability to incur liens to support indebtedness. As a result, if Williams were not in compliance with these covenants, we could be unable to make any borrowings under our $75 million borrowing limit, even if capacity were otherwise available. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Williams ability to comply with the covenants contained in its debt instruments may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, Williams ability to comply with these covenants may be impaired. While we are not individually subject to any financial covenants or ratios under Williams revolving credit facility, Williams and its subsidiaries as a whole are subject to these tests. Accordingly, any breach of these or other covenants, ratios or tests, would terminate our and Williams and its other subsidiaries ability to make additional borrowings under the credit facility and, as a result, could limit our ability to finance our operations, make acquisitions or pay distributions to unitholders. In addition, a breach of these covenants by Williams would cause the acceleration of Williams and, in some cases, our outstanding borrowings under the facility. In the event of acceleration of indebtedness, Williams, the other borrowers or we might not have, or be able to obtain, sufficient funds to make required repayments of the accelerated indebtedness. For more information regarding our debt agreements, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Due to our relationship with Williams, our ability to obtain credit will be affected by Williams credit ratings. If we obtain our own credit rating, any future down grading of a Williams credit rating would likely also result in a down grading of our credit rating. Regardless of whether we have our own credit rating, a down grading of a Williams credit rating could limit our ability to obtain financing in the future upon favorable terms, if at all.

Discovery is not prohibited from incurring indebtedness, which may affect our ability to make distributions to unitholders.

Discovery is not prohibited by the terms of its limited liability company agreement from incurring indebtedness. If Discovery were to incur significant amounts of indebtedness, it may inhibit their ability to make distributions to us. An inability by Discovery to make distributions to us would materially and adversely affect our ability to make distributions to unitholders because we expect distributions we receive from Discovery to represent a significant portion of the cash we distribute to our unitholders.

We do not own all of the interests in the Conway fractionator and in Discovery, which could adversely affect our ability to respond to operate and control these assets in a manner beneficial to us.

Because we do not wholly own the Conway fractionator and Discovery, we may have limited flexibility to control the operation of, dispose of, encumber or receive cash from these assets. Any future disagreements with the other co-owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Discovery may reduce its cash distributions to us in some situations

Discovery s limited liability company agreement provides that Discovery will distribute its available cash to its members on a quarterly basis. Discovery s available cash includes cash on hand less any reserves that may be appropriate for operating its business. As a result, reserves established by Discovery, including those for working capital, will reduce the amount of available cash. The amount of Discovery s quarterly distributions, including the amount of cash reserves not distributed, are to be determined by the members of Discovery s management committee representing a majority-in-interest in Discovery.

We own a 40.0 percent interest in Discovery and an affiliate of Williams owns a 20 percent interest in Discovery. In addition, to the extent Discovery requires working capital in excess of applicable reserves, the Williams member must make working capital advances to Discovery of up to the amount of Discovery s two most recent prior quarterly distributions of available cash, but Discovery must repay any such advances before it can make future distributions to its members. As a result, the repayment of advances could reduce the amount of cash distributions we would otherwise receive from Discovery. In addition, if the Williams member cannot advance working capital to Discovery as described above, Discovery s business and financial condition may be adversely affected.

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We do not operate all of our assets. This reliance on others to operate our assets and to provide other services could adversely affect our business and operating results.

Williams operates all of our assets other than the Carbonate Trend pipeline, which is operated by Chevron, and our Conway fractionator and storage facilities, which we operate. We have a limited ability to control our operations or the associated costs of these operations. The success of these operations is therefore dependent upon a number of factors that are outside our control, including the competence and financial resources of the operators.

We also rely on Williams for services necessary for us to be able to conduct our business. Williams may outsource some or all of these services to third parties, and a failure of all or part of Williams relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on Williams as an operator and on Williams outsourcing relationships, our reliance on Chevron and our limited ability to control certain costs could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than we do.

Discovery competes with other natural gas gathering and transportation and processing facilities and other NGL fractionation facilities located in south Louisiana, offshore in the Gulf of Mexico and along the Gulf Coast, including the Manta Ray/ Nautilus systems, the Trunkline pipeline and the Venice Gathering System and the processing and fractionation facilities that are connected to these pipelines.

Our Conway fractionation facility competes for volumes of mixed NGLs with a ONEOK-owned fractionator located in Hutchinson, Kansas, a ONEOK-owned fractionator located in Medford, Oklahoma, a ONEOK-owned fractionator located in Bushton, Kansas, the other joint owners of the Conway fractionation facility and, to a lesser extent, with fractionation facilities on the Gulf Coast. Our Conway storage facilities compete with ONEOK-owned storage facilities in Bushton, Kansas and in Conway, Kansas, an NCRA-owned facility in Conway, Kansas, a ONEOK-owned facility in Hutchinson, Kansas and an Enterprise Products Partners-owned facility in Hutchinson, Kansas and, to a lesser extent, with storage facilities on the Gulf Coast and in Canada.

In addition, our customers who are significant producers or consumers of NGLs may develop their own processing, fractionation and storage facilities in lieu of using ours. Also, competitors may establish new connections with pipeline systems that would create additional competition for services we provide to our customers. For example, other than the producer gathering lines that connect to the Carbonate Trend pipeline, there are no other sour gas pipelines near our Carbonate Trend pipeline, but the producers that are currently our customers could construct or commission such pipelines in the future. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Our results of storage and fractionation operations are dependent upon the demand for propane and other NGLs. A substantial decrease in this demand could adversely affect our business and operating results.

Our Conway storage and fractionation operations are impacted by demand for propane more than any other NGLs. Conway, Kansas is one of the two major trading hubs for propane and other NGLs in the continental United States. Demand for propane at Conway is principally driven by demand for its use as a heating fuel. However, propane is also used as an engine and industrial fuel and as a petrochemical feedstock in the production of ethylene and propylene. Demand for propane as a heating fuel is significantly affected by weather conditions and the availability of alternative heating fuels such as natural gas. Weather-related demand is subject to normal seasonal fluctuations, but an unusually warm winter could cause demand for propane as a heating fuel to decline significantly. Demand for other NGLs, which include ethane, butane, isobutane and natural gasoline, could be adversely impacted by general economic conditions, a reduction in demand by customers for plastics and other end products made from NGLs, an increase in competition from petroleum-based products, government regulations or other reasons. Any decline in demand for propane or other NGLs could cause a reduction in demand for our Conway storage and fractionation services.

When prices for the future delivery of propane and other NGLs that we store at our Conway facilities fall below current prices, customers are less likely to store these products, which could reduce our storage revenues. This market condition is commonly referred to as backwardation. When the market for propane and other NGLs is in backwardation, the demand for storage capacity at our Conway facilities may decrease. While this would not impact our long-term capacity leases, customers could become less likely to enter into short-term storage contracts.

We may not be able to grow or effectively manage our growth.

A principal focus of our strategy is to continue to grow by expanding our business. Our future growth will depend upon a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:

- identify businesses engaged in managing, operating or owning pipeline, processing, fractionation and storage assets, or other midstream assets for acquisitions, joint ventures and construction projects;
- control costs associated with acquisitions, joint ventures or construction projects;
- consummate acquisitions or joint ventures and complete construction projects, including Discovery s Tahiti lateral expansion project;
- integrate any acquired or constructed business or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations.

A failure to achieve any of these factors would adversely affect our ability to achieve anticipated growth in the level of cash flows or realize anticipated benefits. Furthermore, competition from other buyers could reduce our acquisition opportunities or cause us to pay a higher price than we might otherwise pay. In addition, Williams is not restricted from competing with us. Williams may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

We may acquire new facilities or expand our existing facilities to capture anticipated future growth in natural gas production that does not ultimately materialize. As a result, our new or expanded facilities may not achieve profitability. In addition, the process of integrating newly acquired or constructed assets into our operations may result in unforeseen operating difficulties, may absorb significant management attention and may require financial resources that would otherwise be available for the ongoing development and expansion of our existing operations. Future acquisitions or construction projects could result in the incurrence of indebtedness and additional liabilities and excessive costs that could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders. Further, if we issue additional common units in connection with future acquisitions, unitholders interest in the partnership will be diluted and distributions to unitholders may be reduced.

Discovery s interstate tariff rates are subject to review and possible adjustment by federal regulators, which could have a material adverse effect on our business and operating results. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost of service for rate-making purposes.

The Federal Energy Regulatory Commission, or FERC, pursuant to the Natural Gas Act, regulates Discovery s interstate pipeline transportation service. Under the Natural Gas Act, interstate transportation rates must be just and reasonable and not unduly discriminatory. If the tariff rates Discovery is permitted to charge its customers are lowered by FERC, on its own initiative, or as a result of challenges raised by Discovery s customers or third parties, FERC could require refunds of amounts collected under rates which it finds unlawful. An adverse decision by FERC in approving Discovery s regulated rates could adversely affect our cash flows. Although FERC generally does not regulate the natural gas gathering operations of Discovery under the Natural Gas Act, federal regulation influences the parties that gather natural gas on the Discovery gas gathering system.

Discovery s maximum regulated rate for mainline transportation is scheduled to decrease in 2008. At that time, Discovery may be required to reduce its mainline transportation rate on all of its contracts that have rates above the new maximum rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with FERC seeking to alter this scheduled maximum rate reduction. However, if filed, a rate case may not be successful in even partially preventing the rate reduction. If Discovery makes such a filing, all aspects of Discovery s cost of service and rate design could be reviewed, which could result in additional reductions to its regulated rates.

In July 2004, the United States Court of Appeals for the District of Columbia Circuit, or the D.C. Circuit, issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, SFPP, L.P., or SFPP, were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC s decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income allowance. The FERC s *BP West Coast* remand decision and the new tax allowance policy have been appealed to the D.C. Circuit, and rehearing requests have been filed with respect to the December 16 order. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost-of-service. If Discovery were to file a rate case, as discussed above, it would be required to prove pursuant to the new policy s standard that the inclusion of an income tax allowance in Discovery s cost-of-service was permitted. If the FERC were to disallow a substantial portion of Discovery s income tax allowance, it may be more difficult for Discovery to justify its rates.

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Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are operational risks associated with the gathering, transporting and processing of natural gas and the fractionation and storage of NGLs, including:

- hurricanes, tornadoes, floods, fires, extreme weather conditions and other natural disasters and acts of terrorism;
- damages to pipelines and pipeline blockages;
- leakage of natural gas (including sour gas), NGLs, brine or industrial chemicals;
- collapse of NGL storage caverns;
- operator error;
- pollution;
- fires, explosions and blowouts;
- risks related to truck and rail loading and unloading; and
- risks related to operating in a marine environment.

Any of these or any other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of life, property damage, damage to the environment or other significant exposure to liability. For example, in 2004 we experienced a temporary interruption of service on one of our pipelines due to an influx of seawater while connecting a new lateral. In addition, the Carbonate Trend pipeline is scheduled to be temporarily shut down in the second half of 2006 in connection with restoration activities due to the partial erosion of the pipeline overburden caused by Hurricane Ivan in September 2004. We believe the cost of these restoration activities will be between $3.4 and $4.6 million.

In addition, in anticipation of Hurricane Katrina, the Discovery and Carbonate Trend assets were temporarily shut down on August 27, 2005. The Carbonate Trend assets were off-line for ten days and then experienced a gradual return to pre-hurricane throughput rates by September 19, 2005. In anticipation of Hurricane Rita, the Discovery assets, which were already at reduced throughput from Hurricane Katrina, were temporarily shut down on September 21, 2005. The Discovery assets were off-line for seven days and then continued to experience lower throughput rates through the end of October. We estimate the unfavorable impact of these hurricanes on our 2005 net income was approximately $1.5 million due primarily to the impact of these hurricanes on Discovery s results. Discovery s net income was unfavorably impacted by an approximate loss of $2.3 million in revenue and $1.0 million in uninsured expenses. Discovery s property insurance policy includes a $1.0 million deductible per occurrence. Please read Management s Discussion and Analysis of Financial Condition Recent Events.

Insurance may be inadequate, and in some instances, we may be unable to obtain insurance on commercially reasonable terms, if at all. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to unitholders.

Pipeline integrity programs and repairs may impose significant costs and liabilities on us.

In December 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs for gas transportation pipelines located where a leak or rupture could do the most harm in high consequence areas. The final rule requires operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

improve data collection, integration and analysis;

repair and remediate the pipeline as necessary; and

implement preventive and mitigating actions.

The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002. The final rule became effective on January 14, 2004. In response to this new Department of Transportation rule, we have initiated pipeline integrity testing programs that are intended to assess pipeline integrity. In addition, we have voluntarily initiated a testing program to assess the integrity of the brine pipelines of our Conway storage facilities. In 2005, Conway replaced two sections of brine systems at a cost of $0.2 million. This work is in anticipation of integrity testing scheduled to begin in 2006. The results of these testing programs could cause us to incur significant capital and operating expenditures in response to any repair, remediation, preventative or mitigating actions that are determined to be necessary.

Additionally, the transportation of sour gas in our Carbonate Trend pipeline necessitates a corrosion control program in order to protect the integrity of the pipeline and prolong its life. Our corrosion control program may not be successful and the sour gas could compromise pipeline integrity. Our inability to reduce corrosion on our Carbonate Trend pipeline to acceptable levels could significantly reduce the service life of the pipeline and could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders. Please read Business The Carbonate Trend Pipeline General .

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of increased costs to retain necessary land use. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to unitholders.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities.

The risk of substantial environmental costs and liabilities is inherent in natural gas gathering, transportation and processing, and in the fractionation and storage of NGLs, and we may incur substantial environmental costs and liabilities in the performance of these types of operations. Our operations are subject to stringent federal, state and local laws and regulations relating to protection of the environment. These laws include, for example:

the Federal Clean Air Act and analogous state laws, which impose obligations related to air emissions;

the Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act, or CWA, and analogous state laws, which regulate discharge of wastewaters from our facilities to state and federal waters;

the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, and analogous state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal; and

the federal Resource Conservation and Recovery Act, also known as RCRA, and analogous state laws that impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Various governmental authorities, including the U.S. Environmental Protection Agency, or EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under CERCLA, RCRA and analogous state laws for the remediation of contaminated areas.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of the products we gather, transport, process, fractionate and store, air emissions related to our operations, historical industry operations, waste disposal practices, and the prior use of flow meters containing mercury, some of which may be material. Private parties, including the owners of properties through which our pipeline systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third party hydrocarbon storage and processing operations and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, some of which may be material.

For example, the Kansas Department of Health and Environment, or the KDHE, regulates the storage of NGLs and natural gas in the state of Kansas. This agency also regulates the construction, operation and closure of brine ponds associated with such storage facilities. In response to a significant incident at a third party facility, the KDHE recently promulgated more stringent regulations regarding safety and integrity of brine ponds and storage caverns. These regulations are subject to interpretation and the costs associated with compliance with these regulations could vary significantly depending upon the interpretation of these regulations. The KDHE has advised us that one such regulation relating to the metering of NGL volumes that are injected and withdrawn from our caverns may be interpreted and enforced to require the installation of meters at each of our well bores. We have informed the KDHE that we disagree with this interpretation, and the KDHE has asked us to provide it with additional information. We have made a proposal to install individual cavern meters at 13 caverns that are connected to the fractionator and NGL pipelines. The estimated cost for this work is $220,000. If this proposal is not accepted we estimate that the cost of installing a meter at each of our well bores at two of our Conway storage facilities would total approximately $3.9 million over three years. Additionally, incidents similar to the incident at a third party facility that prompted the recent KDHE regulations could prompt the issuance of even stricter regulations.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us. Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, new environmental regulations might adversely affect our products and activities, including processing, fractionation, storage and transportation, as well as waste management and air emissions. Federal and state agencies also could impose additional safety requirements, any of which could affect our profitability.

Potential changes in accounting standards might cause us to revise our financial results and disclosure in the future.

Recently-discovered accounting irregularities in various industries have forced regulators and legislators to take a renewed look at accounting practices, financial disclosure, the relationships between companies and their independent auditors, and retirement plan practices. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets and liabilities. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Terrorist attacks have resulted in increased costs, and attacks directed at our facilities or those of our suppliers and customers could disrupt our operations.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the United States government has issued warnings that energy assets may be the future target of terrorist organizations. These developments have subjected our operations to increased risks and costs. The long-term impact that terrorist attacks and the threat of terrorist attacks may have on our industry in general, and on us in particular, is not known at this time. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways. In addition, uncertainty regarding future attacks and war cause global energy markets to become more volatile. Any terrorist attack on our facilities or those of our suppliers or customers could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Changes in the insurance markets attributable to terrorists attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in financial markets as a result of terrorism or war could also affect our ability to raise capital.

We are exposed to the credit risk of our customers and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers. Our credit procedures and policies may not be adequate to fully eliminate customer credit risk. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to unitholders.

Risks Inherent in an Investment in Us

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

Williams owns the two percent general partner interest and a 59 percent limited partner interest in us and owns and controls our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and executive officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, Williams. Conflicts of interest may arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Williams or its affiliates to pursue a business strategy that favors us;

- our general partner is allowed to take into account the interests of parties other than us, such as Williams, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- Williams and its affiliates may engage in competition with us;

- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

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our general partner determines the amount and timing of our cash reserves, asset purchases and sales, capital expenditures, borrowings and issuances of additional partnership securities, each of which can affect the amount of cash that is distributed to our unitholders;

our general partner determines the amount and timing of any capital expenditures, as well as whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not, which determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;

in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;

our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

our general partner intends to limit its liability regarding our contractual and other obligations;

our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80 percent of the common units;

our general partner controls the enforcement of obligations owed to us by it and its affiliates; and

our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please read Certain Relationships and Related Transactions Omnibus Agreement.

Our partnership agreement limits our general partner s fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership;

provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

provides that resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be fair and reasonable to us, as determined by our general partner in good faith, and that, in determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

provides that our general partner, its affiliates and their officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

By purchasing a common unit, a common unitholder will be bound by the provisions in the partnership agreement, including the provisions discussed above.

Even if unitholders are dissatisfied, they cannot currently remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Williams. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The vote of the holders of at least $66^{2}/3$ percent of all outstanding common and subordinated units voting together as a single class is required to remove our general partner. Accordingly, our unitholders are currently unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent the general partner s removal. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal of our general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests.

Cause is narrowly defined in our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of our general partner from transferring their member interest in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors and officers of the general partner with their own choices and to control the decisions taken by the board of directors and officers of the general partner. In addition, pursuant to the omnibus agreement with Williams, any new owner of the general partner would be required to change our name so that there would be no further reference to Williams.

Increases in interest rates may cause the market price of our common units to decline.

An increase in interest rates may cause a corresponding decline in demand for equity investments in general, and in particular for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

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We may issue additional common units without unitholder approval, which would dilute unitholder ownership interests.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units subject to the limitations imposed by the New York Stock Exchange. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders proportionate ownership interest in us will decrease;
- the amount of cash available to pay distributions on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Williams and its affiliates may compete directly with us and have no obligation to present business opportunities to us.

The omnibus agreement does not prohibit Williams and its affiliates from owning assets or engaging in businesses that compete directly or indirectly with us. Williams may acquire, construct or dispose of additional midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets. In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to Williams and its affiliates. As a result, neither Williams nor any of its affiliates has any obligation to present business opportunities to us. Please read Certain Relationships and Related Transactions Omnibus Agreement.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80 percent of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, non-affiliated unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Such unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would not longer be subject to the reporting requirements of the Securities Exchange Act of 1934.

Our partnership agreement restricts the voting rights of unitholders owning 20 percent or more of our common units.

Our partnership agreement restricts unitholders voting rights by providing that any units held by a person that owns 20 percent or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. The partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Cost reimbursements due our general partner and its affiliates will reduce cash available to pay distributions to unitholders.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf, which will be determined by our general partner. These expenses will include all costs incurred by the general partner and its affiliates in managing and operating us, including costs for rendering corporate staff and support services to us. Please read Certain Relationships and Related Transactions. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates could adversely affect our ability to pay cash distributions to unitholders.

Unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business. Unitholders may also have liability to repay distributions.

As a limited partner in a partnership organized under Delaware law, unitholders could be held liable for our obligations to the same extent as a general partner if they participate in the control of our business. Our general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

Common units held by affiliates of Williams eligible for future sale may have adverse effects on the price of our common units.

As of February 28, 2006, affiliates of Williams held 1,250,000 common units and 7,000,000 subordinated units, representing a 59 percent limited partnership interest in us. The affiliates of Williams may, from time to time, sell all or a portion of their common units or subordinated units. Sales of substantial amounts of their common units or subordinated units, or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and at a price that we deem appropriate.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS were to treat us as a corporation or if we were to become subject to entity-level taxation for state tax purposes, then our cash available to pay distributions to unitholders would be substantially reduced.

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35 percent. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders, likely causing a substantial reduction in the value of the common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. For example, 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. If any state were to impose a tax upon us as an entity, the cash available to pay distributions to unitholders would be reduced. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will be borne by our unitholders and our general partner.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel s conclusions. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

Unitholders may be required to pay taxes on their share of our income even if unitholders do not receive any cash distributions from us.

Unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

The tax gain or loss on the disposition of our common units could be different than expected.

If a unitholder sell its common units, it will recognize gain or loss equal to the difference between the amount realized and its tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income it was allocated for a common unit, which decreased its tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than its tax basis in that common unit, even if the price the unitholder receives is less than its original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder.

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform will all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to unitholders. It also

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could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to unitholder tax returns.

Unitholders will likely be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own property and conduct business in Kansas, Louisiana and Alabama. We may own property or conduct business in other states or foreign countries in the future. It is the unitholder s responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our common units.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

FORWARD LOOKING STATEMENTS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Certain matters discussed in this annual report, excluding historical information, include forward-looking statements statements that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report which address activities, events or developments which we expect, believe or anticipate will or may occur in the future are forward-looking statements. Forward-looking statements can be identified by words such as may, anticipates, believes, expects, planned, scheduled, could, continues, estimates, forecasts, might, potential, projects or similar expressions. Simi statements that describe our future plans, objectives or goals are also forward-looking statements.

Although we believe these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document. These risks and uncertainties include, among other things:

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

Because of the natural decline in production from existing wells, the success of our gathering business depends on our ability to obtain new sources of natural gas supply, which is dependent on factors beyond our control. Any decrease in supplies of natural gas could adversely affect our business and operating results.

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- Our processing, fractionation and storage businesses could be affected by any decrease in the price of natural gas liquids or a change in the price of natural gas liquids relative to the price of natural gas.

- Williams revolving credit facility and Williams public indentures contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

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

- Even if unitholders are dissatisfied, they cannot currently remove our general partner without its consent.

- Unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

- Our operations are subject to operational hazards and unforeseen interruptions for which we may or may not be adequately insured.

- Lower natural gas and oil prices could adversely affect our fractionation and storage businesses.

- We depend on certain key customers and producers for a significant portion of our revenues and supply of natural gas and natural gas liquids. The loss of any of these key customers or producers could result in a decline in our revenues and cash available to pay distributions.

- If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport natural gas and natural gas liquids or to treat natural gas, our revenues and cash available to pay distributions could be adversely affected.

When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report. The risk factors discussed in this Item 1A and other factors noted throughout this report could cause our actual results to differ materially from those contained in any forward-looking statement. The forward-looking statements included in this report are only made as of the date of this report and we undertake no obligation to publicly update forward-looking statements to reflect subsequent events or circumstances.

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

The information called for by this item is provided in Note 13, Commitments and Contingencies included in the Notes to Consolidated Financial Statements of this report, which information is incorporated into this Item 3 by reference.

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***

Market Information, Holders and Distributions

Our common units are listed on the New York Stock Exchange under the symbol WPZ. At the close of business on March 1, 2006, there were 7,006,146 common units outstanding, held by approximately 3,494 holders, including common units held in street name and by affiliates of Williams. The high and low sales price ranges (New York Stock Exchange composite transactions) and distributions declared by quarter for each of the last two fiscal quarters of 2005 since the IPO of our common units in August 2005 are as follows:

	2005		
Quarter	**High**	**Low**	**Distribution(2)**
3rd(1)	$ 32.75	$ 24.89	$ 0.1484(3)
4th	$ 34.46	$ 29.75	$ 0.35

(1) For the period from August 23, 2005 through September 30, 2005.

(2) Represents cash distributions attributable to the quarter and declared and paid or to be paid within 45 days after quarter end. We paid cash distributions to our general partner with respect to its two percent general partner interest that totaled $42,400 for the period from August 23, 2005 through September 30, 2005. We declared cash distributions to our general partner with respect to its two percent general partner interest that totaled $142,400 for the period from August 23, 2005 through December 31, 2005.

(3) The distribution for the third quarter of 2005 represents a proration of the minimum quarterly distribution per common and subordinated unit for the period from August 23, 2005, the date of the closing of our initial public offering of common units, through September 30, 2005.

Distributions of Available Cash

Within 45 days after the end of each quarter (beginning with the quarter ending September 30, 2005) we will distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Available cash generally means, for each fiscal quarter all cash on hand at the end of the quarter:

less the amount of cash reserves established by our general partner to:

- provide for the proper conduct of our business (including reserves for future capital expenditures and for our anticipated credit needs);
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distribution to our unitholders and to our general partner for any one or more of the next four quarters;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made. Working capital borrowings are generally borrowings that will be made under our working capital facility with Williams and in all cases are used solely for working capital purposes or to pay distributions to partners.

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Upon the closing of our IPO, affiliates of Williams received an aggregate of 7,000,000 subordinated units. During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.35 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

The subordination period will extend until the first day of any quarter beginning after June 30, 2008 that each of the following tests are met: (i) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date; (ii) the adjusted operating surplus (as defined in its partnership agreement) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the general partner interest during those periods; and (iii) there are no arrearages in payment of the minimum quarterly distribution on the common units.

In addition, the subordination period may terminate before June 30, 2008 if the following tests are met: (i) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $2.10 (150 percent of the annualized minimum quarterly distribution) for the immediately preceding four-quarter period; (ii) the adjusted operating surplus generated during such four-quarter period equaled or exceeded $2.10 (150 percent of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during such four-quarter period on a fully diluted basis and the related distribution on the general partner interest during such four-quarter period; and (iii) there are no arrearages in payment of the minimum quarterly distribution on the common units.

If the unitholders remove the general partner without cause, the subordination period may also end before June 30, 2008.

We will make distributions of available cash from operating surplus for any quarter during any subordination period in the following manner: (i) first, 98 percent to the common unitholders, pro rata, and two percent to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; (ii) second, 98 percent to the common unitholders, pro rata, and two percent to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period; (iii) third, 98 percent to the subordinated unitholders, pro rata, and two percent to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and (iv) thereafter, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

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

	Total Quarterly Distribution Target Amount		Marginal Percentage Interest in Distributions	
			Unitholders	**General Partner**
Minimum Quarterly Distribution		$0.35	98%	2%
First Target Distribution	up to $0.4025		98%	2%

Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	Above $0.5250	50%	50%

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Item 6. ***Selected Financial and Operational Data***

The following table shows selected financial and operating data of Williams Partners L.P. and of Discovery Producer Services LLC for the periods and as of the dates indicated. We derived the financial data as of December 31, 2005 and 2004 and for the years ended December 31, 2005, 2004 and 2003 in the following table from, and that information should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this document. All other financial data are derived from our financial records.

The table should also be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations for information concerning significant trends in the financial condition and results of operations.

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(Dollars in thousands, except per unit amounts)				
Statement of Income Data:					
Revenues	$ 51,769	$ 40,976	$ 28,294	$ 25,725	$ 29,164
Costs and expenses	46,568	32,935	21,250	16,542	23,692
Operating income	5,201	8,041	7,044	9,183	5,472
Equity earnings (loss) Discovery	8,331	4,495	3,447	2,026	(13,401)
Impairment of investment in Discovery		(13,484)(a)			
Interest expense	(8,238)	(12,476)	(4,176)	(3,414)	(4,173)
Interest income	165				
Income (loss) before cumulative effect of change in accounting principle	$ 5,459	$ (13,424)	$ 6,315	$ 7,795	$ (12,102)
Net income (loss)(b)	$ 4,831	$ (13,424)	$ 5,216	$ 7,795	$ (12,102)
Income (loss) before cumulative effect of change in accounting principle per limited partner unit:(d)					
Common unit	$ 0.49	N/A	N/A	N/A	N/A
Subordinated unit	$ 0.49	N/A	N/A	N/A	N/A
Net income (loss) per limited partner unit:(d)					
Common unit	$ 0.44	N/A	N/A	N/A	N/A
Subordinated unit	$ 0.44	N/A	N/A	N/A	N/A
Balance Sheet Data (at period end):					
Total assets	$ 240,941	$ 219,361	$ 230,150(c)	$ 125,069	$ 122,239
Property, plant and equipment, net	67,931	67,793	69,695	72,062	75,269

Investment in Discovery	150,260	147,281(a)	156,269(c)	49,323	44,499
Advances from affiliate		186,024	187,193(c)	90,996	95,535
Partners capital	221,655	16,668	30,092	22,914	15,236
Cash Flow Data:					
Cash distributions declared per unit	$ 0.1484	N/A	N/A	N/A	N/A
Cash distributions paid per unit	$ 0.1484	N/A	N/A	N/A	N/A

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	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(Dollars in thousands, except per unit amounts)				
Operating Information:					
Williams Partners L.P.:					
Conway storage revenues	$ 20,290	$ 15,318	$ 11,649	$ 10,854	$ 11,134
Conway fractionation volumes (bpd) our 50%	39,965	39,062	34,989	38,234	40,713
Carbonate Trend gathered volumes (MMBtu/d)	35,605	49,981	67,638	57,060	55,746
Discovery Producer Services 100%:					
Gathered volumes (MMBtu/d)	345,098	348,142	378,745	425,388	226,820
Gross processing margin (¢/MMbtu)	19¢	17¢	17¢	12¢	N/A

(a) The $13.5 million impairment of our equity investment in Discovery in 2004 reduced the investment balance. See Note 6 of the Notes to Consolidated Financial Statements.

(b) Our operations are treated as a partnership with each member being separately taxed on its ratable share of our taxable income. Therefore, we have excluded income tax expense from this financial information.

(c) In December 2003, we made a $101.6 million capital contribution to Discovery, which Discovery subsequently used to repay maturing debt. We funded this contribution with an advance from Williams. Prior to the closing of our initial public offering, Williams forgave the entire advances from affiliates balance.

(d) The period of August 23, 2005 through December 31, 2005.

Item 7. ***MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 8 of this annual report.

General

We are a Delaware limited partnership formed in February 2005 by Williams to own, operate and acquire a diversified portfolio of complementary energy assets. On August 23, 2005, we completed our IPO of 5,000,000 common units at a price of $21.50 per unit. We used proceeds from the sale of the units totaling $100.2 million were used to:

distribute $58.8 million to affiliates of Williams in part to reimburse Williams for capital expenditures relating to the assets contributed to us, including a gas purchase contract contributed to us;

provide $24.4 million to make a capital contribution to Discovery to fund an escrow account required in connection with the Tahiti pipeline lateral expansion project;

provide $12.7 million of additional working capital; and pay $4.3 million of expenses associated with our IPO and related formation transactions.

Additionally, at the closing of our IPO, the underwriters fully exercised their option to purchase 750,000 common units at the IPO price of $21.50 per unit from certain affiliates of Williams.

Prior to the closing of our IPO, our assets were held by wholly owned subsidiaries of Williams. Upon the closing of our IPO, these Williams subsidiaries transferred the assets and the related liabilities to us. The following discussion includes the historical period prior to the closing of our IPO.

Overview

We are principally engaged in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. We manage our business and analyze our results of operations on a segment basis. Our operations are divided into two business segments:

Gathering and Processing. Our Gathering and Processing segment includes (1) our 40 percent ownership interest in Discovery and (2) the Carbonate Trend gathering pipeline off the coast of Alabama. Discovery owns an integrated natural gas gathering and transportation pipeline system extending from offshore in the Gulf of Mexico to a natural gas processing facility and an NGL fractionator in Louisiana. These assets generate revenues by providing natural gas gathering, transporting and processing services and integrated NGL fractionating services to customers under a range of contractual arrangements. Although Discovery includes fractionation operations, which would normally fall within the NGL Services segment, it is primarily engaged in gathering and processing and is managed as such.

NGL Services. Our NGL Services segment includes three integrated NGL storage facilities and a 50 percent undivided interest in a fractionator near Conway, Kansas. These assets generate revenues by providing stand-alone NGL fractionation and storage services using various fee-based contractual arrangements where we receive a fee or fees based on actual or contracted volumetric measures.

Executive Summary

Overall our 2005 results of operations met our expectations for these assets, although we faced unusual operating conditions the last few months of 2005. Discovery and Carbonate Trend were impacted by Hurricanes Dennis, Katrina and Rita, and Conway saw an impact from a delay in the peak usage of retail propane due to an unusually moderate winter. The hurricanes created an unfavorable impact for our traditional natural gas supplies but also provided an opportunity for Discovery to assist other producers and processors with stranded gas by offering available firm transportation capacity to them through two open seasons discussed below in Recent Events. Discovery replaced some of its lost revenue while helping to bring the supply of natural gas back to the nation in advance of winter. We continue to monitor the longer-term effects these hurricanes had on Discovery s traditional sources of natural gas, which might cause lower than expected gathered volumes from these sources in 2006. Conway experienced an increased demand for propane storage services as a result of warm early-winter temperatures. Our results were negatively impacted by unfavorable commodity price movements on operating supply inventory we held at Conway and by higher general and administrative costs. Our liquidity continues to meet our expectations. We have had no borrowings under our revolving credit facilities and have successfully met our minimum quarterly distributions. Our capitalization and relationship with Williams has us well-positioned to grow our partnership through both internal projects, including Discovery s Tahiti expansion and acquisition transactions with Williams and other third parties.

Recent Events

In July 2005, Discovery executed an agreement with three producers to construct an approximate 35-mile gathering pipeline lateral to connect Discovery s existing pipeline system to these producers production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion will have a design capacity of approximately 200 million cubic feet per day, and its anticipated completion date is May 1, 2007. We expect the total construction cost of the Tahiti pipeline lateral expansion project to be approximately $69.5 million, of which our 40 percent share will be approximately $27.8 million. In September 2005, we made a $24.4 million contribution to Discovery to cover a substantial portion of the total expenditures attributable to our share of these costs. We funded this contribution with proceeds from our IPO. The omnibus agreement, executed in connection with our IPO, provides that Williams will reimburse us for our remaining share of $3.4 million once the escrow funds have been exhausted.

On July 8, 2005, the Discovery and Carbonate Trend assets were temporarily shut down in anticipation of Hurricane Dennis. The Discovery and Carbonate Trend assets were off-line for four and five days, respectively. We estimate the unfavorable impact of this hurricane on our 2005 net income was approximately $150,000 in lost revenue.

On August 29, 2005, Hurricane Katrina struck the Gulf Coast area. In anticipation of the hurricane, the Discovery and Carbonate Trend assets were temporarily shut down on August 27, 2005. The Discovery assets were off-line for six days and then continued to experience lower throughput rates until being temporarily shut down for Hurricane Rita. The Carbonate Trend assets were off-line for 10 days and then experienced a gradual return to pre-hurricane throughput rates by September 19, 2005. On September 24, 2005, Hurricane Rita struck the Gulf Coast area. In anticipation of the hurricane, the Discovery assets, which were already at reduced throughput from Hurricane Katrina, were temporarily shut down on September 21, 2005. The Discovery assets were off-line for seven days and then continued to experience lower throughput rates through the end of the third quarter. Discovery s net income was unfavorably impacted by an approximate loss of $2.3 million in revenue and $1.0 million in uninsured expenses. Discovery s property insurance policy includes a $1.0 million deductible per occurrence. We estimate the unfavorable impact of Hurricanes Katrina and Rita on our 2005 net income was approximately $1.5 million due primarily to the impact of these hurricanes on Discovery s results.

In October 2005, Discovery conducted two expedited Federal Energy Regulatory Commission (FERC) open seasons for firm transportation to provide outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. Both of these open seasons were for up to 250,000 MMBtu/d. The first of these included the construction of a new receipt point at Texas Eastern Transmission Company s (TETCO) Larose compressor station in Lafourche Parish, Louisiana. The second is via an existing interconnection to Tennessee Gas Pipeline s (TGP) Line 500 in Terrebonne Parish, Louisiana. We began receiving additional incremental volumes from these receipt points in November and December 2005 and anticipate continued throughput through the first quarter of 2006. Shippers reimbursed Discovery for the majority of the capital necessary to establish these connections. We estimate the favorable impact of these open seasons on our 2005 net income was approximately $4.6 million in increased revenue less related expenses.

For January 2006, the average gathering volumes for Discovery were approximately 694,000 million British Thermal Units per day (MMBtu/d). This volume includes approximately 412,000 MMBtu/d from multiple customers whose gas is normally processed at another plant that was severely damaged by Hurricane Katrina and 282,000 MMBtu/d from Discovery s traditional sources.

Potential Acquisition Candidate Identified

On November 1, 2005, we announced that we and Williams had identified an approximate 25 percent interest in Williams existing gathering and processing assets in the Four Corners area as our initial candidate to be considered for acquisition. The terms of this proposed transaction, including price, will be subject to approval by the boards of directors of our general partner and of Williams.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measures to analyze our segment performance, including the performance of Discovery. These measurements include:

- pipeline throughput volumes;
- gross processing margins;
- fractionation volumes;
- storage revenues; and
- operating and maintenance expenses.

Pipeline Throughput Volumes. We view throughput volumes on Discovery s pipeline system and our Carbonate Trend pipeline as an important component of maximizing our profitability. We gather and transport

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natural gas under fee-based contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time. Accordingly, to maintain or increase throughput levels on these pipelines and the utilization rate of Discovery s natural gas processing plant and fractionator, we and Discovery must continually obtain new supplies of natural gas. Our ability to maintain existing supplies of natural gas and obtain new supplies are impacted by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines and (2) our ability to compete for volumes from successful new wells in other areas. We routinely monitor producer activity in the areas served by Discovery and Carbonate Trend and pursue opportunities to connect new wells to these pipelines.

Gross Processing Margins. We view total gross processing margins as an important measure of Discovery s ability to maximize the profitability of its processing operations. Gross processing margins include revenue derived from:

- the rates stipulated under fee-based contracts multiplied by the actual MMBtu volumes;
- sales of NGL volumes received under percent-of-liquids contracts for Discovery s account; and
- sales of natural gas volumes that are in excess of operational needs.

The associated costs, primarily shrink replacement gas and fuel gas, are deducted from these revenues to determine processing gross margin. Shrink replacement gas refers to natural gas that is required to replace the Btu content lost when NGLs are extracted from the natural gas stream. In certain prior years, such as 2003, we generated significant revenues from the sale of excess natural gas volumes. However, in response to a final rule issued by FERC in 2004, we expect that Discovery will generate only minimal revenues from the sale of excess natural gas in the future.

Discovery s mix of processing contract types and its operation and contract optimization activities are determinants in processing revenues and gross margins. Please read Our Operations Gathering and Processing Segment.

Fractionation Volumes. We view the volumes that we fractionate at the Conway fractionator as an important measure of our ability to maximize the profitability of this facility. We provide fractionation services at Conway under fee-based contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes fractionated.

Storage Revenues. Our storage revenues are derived by applying the average demand charge per barrel to the total volume of storage capacity under contract. Given the nature of our operations, our storage facilities have a relatively higher degree of fixed verses variable costs. Consequently, we view total storage revenues, rather than contracted capacity or average pricing per barrel, as the appropriate measure of our ability to maximize the profitability of our storage assets and contracts. Total storage revenues include the monthly recognition of fees received for the storage contract year and shorter-term storage transactions.

Operating and Maintenance Expenses. Operating and maintenance expenses are costs associated with the operations of a specific asset. Direct labor, fuel, utilities, contract services, materials, supplies, insurance and ad valorem taxes comprise the most significant portion of operating and maintenance expenses. Other than fuel, these expenses generally remain relatively stable across broad ranges of throughput volumes but can fluctuate depending on the activities performed during a specific period. For example, plant overhauls and turnarounds result in increased expenses in the periods during which they are performed. We include fuel cost in our operating and maintenance expense, although it is generally recoverable from our customers in our NGL Services segment. As noted above, fuel costs in our Gathering and Processing segment are a component in assessing our gross processing margins.

In addition to the foregoing measures, we also review our general and administrative expenditures, substantially all of which are incurred through Williams. In an omnibus agreement, executed in connection with our IPO, Williams agreed to provide a five-year partial credit for general and administrative expenses incurred on our behalf. The amount of this credit in 2005 was $3.9 million, which was pro rated for the period from the closing of our IPO through year end. The pro rated amount totaled $1.4 million. The amount of the credit will be $3.2 million in 2006 and will decrease by approximately $800,000 in each subsequent year.

We record total general and administrative costs, including those costs that are subject to the credit by Williams, as an expense, and we record the credit as a capital contribution by our general partner. Accordingly, our net income does not reflect the benefit of the credit received from Williams. However, the cost subject to this credit is allocated entirely to our general partner. As a result, the net income allocated to limited partners on a per-unit basis reflects the benefit of this credit.

Our Operations

Gathering and Processing Segment

Our Gathering and Processing segment consists of our interest in Discovery and our Carbonate Trend Pipeline. These assets generate revenues by providing natural gas gathering, transporting and processing services and NGL fractionating services to customers under a range of contractual arrangements. Although Discovery includes fractionation operations, which would normally fall within the NGL Services segment, it is primarily engaged in gathering and processing and is managed as such. As a result, this equity investment, which can only be presented in one segment, is considered part of the Gathering and Processing segment. For additional information on these activities, and the assets and activities described below, please read Business and Properties Gathering and Processing The Discovery Assets.

Gathering and Transportation Contracts

We generate gathering and transportation revenues by applying the set tariff or contracted rate to the contractually-defined volumes of gas gathered or transported. Discovery s mainline and its FERC-regulated laterals generate revenues through two types of arrangements firm transportation service and traditional interruptible transportation service. Under the firm transportation arrangement, producers are required to dedicate reserves for the life of the lease, but pay no reservation fees for firm capacity. Under the interruptible transportation arrangement, no reserve dedication is required. Customers with firm transportation arrangements are entitled to a higher priority of service, in the case of a full pipeline, than customers who contract for interruptible transportation service. Firm transportation services represent the majority of the revenues from Discovery s FERC-regulated business. Discovery also offers a third type of arrangement, traditional firm service with reservation fees, but none of Discovery s customers currently contract for this type of transportation service.

Discovery s maximum regulated rate for mainline transportation is scheduled to decrease in 2008. At that time, Discovery will be required to reduce its mainline transportation rate on all of its contracts that have rates above the new reduced rate. This could reduce the revenues generated by Discovery. Discovery may elect to file a rate case with FERC seeking to alter this scheduled reduction. However, if filed, we cannot assure you that a rate case would be successful in even partially preventing the rate reduction. Please read Risk Factors Risks Inherent in Our Business Discovery s interstate tariff rates are subject to review and possible adjustment by federal regulators, which could have a material adverse effect on our business and operating results. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost of service for rate-making purposes and Business and Properties FERC Regulation.

Carbonate Trend s three contracts have terms tied to the life of the customer s lease. The actual terms of these contracts will vary depending on the productive life of the natural gas reserves underlying these leases. However, the per-unit gathering fee associated with two of our three Carbonate Trend gathering contracts was negotiated on a bundled basis that includes transportation along a segment of Transcontinental Gas Pipe Line Company, or Transco, a wholly owned subsidiary of Williams. The gathering fees we receive are dependent upon whether our customer elects to utilize this Transco capacity. If a customer elects to use the Transco capacity, our gathering fee is determined by subtracting the Transco tariff from the total negotiated fee and generally results in a rate lower than would be realized if the customer elects not to utilize Transco s capacity. The rate associated with Transco capacity is based on a FERC tariff that is subject to change. Accordingly, if the Transco rate increases, our gathering fees will be reduced. The customers with these bundled contracts

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must make an annual election to receive this capacity. Both customers elected to use this capacity during 2004 and only one elected to use this capacity in 2005 and 2006.

The gathering and transportation revenues that we generate under fee-based contracts are not directly affected by changing commodity prices. However, to the extent a sustained decline in commodity prices realized by our customers results in a decline in the producers future drilling and development activities, our revenues from these contracts could be reduced in the long term.

Processing and Fractionation Contracts

Fee-based contracts. Discovery generates fee-based fractionation revenues based on the volumes of mixed NGLs fractionated and the per-unit fee charged, which is subject to adjustment for changes in certain fractionation expenses, including natural gas fuel and labor costs. Some of Discovery s natural gas processing contracts are also fee-based contracts under which revenues are generated based on the volumes of natural gas processed at its natural gas processing plant. As discussed below, Discovery also processes natural gas under percent-of-liquids contracts.

The processing revenues that Discovery generates under fee-based contracts are not directly affected by changing commodity prices. However, to the extent a sustained decline in commodity prices realized by our customers results in a decline in the producers future drilling and development activities, our revenues from these contracts could be reduced due to long-term development declines.

Percent-of-liquids contracts. Under percent-of-liquids contracts, Discovery (1) processes natural gas for customers, (2) delivers to customers an agreed-upon percentage of the NGLs extracted in processing and (3) retains a portion of the extracted NGLs. Discovery generates revenue by selling these retained NGLs to other parties at market prices. Some of Discovery s percent-of-liquids contracts have a bypass option. Under this option, customers may elect not to process, or bypass, their natural gas on a monthly basis, in which case, Discovery retains a portion of the customers natural gas in lieu of NGLs as a fee. Discovery uses its retained natural gas to partially offset the amount of natural gas Discovery must purchase in the market for shrink replacement gas and natural gas consumed as fuel. Discovery may choose to process natural gas that a customer has elected to bypass, but it then must deliver natural gas with an equivalent Btu content to the customer. Discovery would not elect to process bypassed gas if market conditions posed the risk of negative processing margins. Please read Operation and Contract Optimization.

Under Discovery s percent-of-liquids contracts, revenues either increase or decrease as a result of a corresponding change in the market prices of NGLs. For contracts with a bypass option, and depending upon whether the customer elects the bypass election, Discovery s revenues would either increase or decrease as a result of a corresponding change in the relative market prices of NGLs and natural gas.

Discovery is also a party to a small number of keep-whole gas processing arrangements. Under these arrangements, a processor retains NGLs removed from a customer s natural gas stream but must deliver gas with an equivalent Btu content to the customer, either from the processor s inventory or through open market purchases. A rise in natural gas prices as compared to NGL prices can cause the processor to suffer negative margins on keep-whole arrangements. The natural gas associated with Discovery s keep-whole arrangements has a low NGL content. As a result, this gas does not require processing to be shipped on downstream pipelines. Consequently, under unfavorable market conditions, Discovery may earn little or no margin on these arrangements, but is not exposed to negative processing margins. Discovery does not intend to enter into additional keep-whole arrangements in the future that would represent a material amount of processing volumes.

Substantially all of Discovery s gas gathering, transportation, processing and fractionation contracts have terms that expire at the end of the customer s natural resource lease. The actual terms of these contracts will vary depending on life of the natural gas reserves underlying these leases. As a result of Discovery s current contract mix, Discovery takes title to approximately one-half of the mixed NGL volumes leaving its natural gas processing plant. A Williams subsidiary serves as a marketer for these NGLs and, under the terms of its agreement with Discovery, purchases substantially all of Discovery s NGLs for resale to end users. As a result,

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a significant portion of Discovery s revenues are reported as affiliate revenues even though Williams is not a producer that supplies the Discovery pipeline system with any volumes of natural gas. If the arrangement with the Williams subsidiary were terminated, we believe that Discovery could contract with a third party marketer or perform its own marketing services.

Operation and Contract Optimization

Long-haul natural gas pipelines, generally interstate pipelines that serve end use markets, publish specifications for the maximum NGL content of the natural gas that they will transport. Normally, NGLs must be removed from the natural gas stream at a gas processing facility in order to meet these pipeline specifications. It is common industry practice, however, to blend some unprocessed gas with processed gas to the extent that the combined gas stream is still able to meet the pipeline specifications at the point of injection into the long-haul pipeline.

Although it is typically profitable for producers to separate NGLs from their natural gas streams, there can be periods of time in which the relative value of NGL market prices to natural gas market prices may result in negative processing margins and, as a result, lack of profit from NGL extraction. Because of this margin risk, producers are often willing to pay for the right to bypass the gas processing facility if the circumstances permit. Owners of gas processing facilities may often allow producers to bypass their facilities if they are paid a bypass fee. The bypass fee helps to compensate the gas processing facility for the loss of processing volumes.

Under Discovery s contracts that include a bypass option, Discovery s customers may exercise their option to bypass the gas processing plant. Producers with these contracts notify Discovery of their decision to bypass prior to the beginning of each month. For the natural gas volumes that producers have chosen to bypass, Discovery evaluates current commodity prices and then decides whether it will process the gas for its own account and retain the separated NGLs for sale to third parties. The customer pays a bypass fee regardless of whether or not Discovery decides to process the gas for its own account. Discovery s decision is determined by the value of the NGLs it will separate during the month compared to the cost of the replacement volume of natural gas it must purchase to keep the producer whole.

By providing flexibility to both producers and gas processors, bypass options can enhance both parties profitability. Discovery manages its operations given its contract portfolio, which contains a proportion of contracts with this option that is appropriate given current and expected future commodity market conditions.

NGL Services Segment

We generate revenues by providing NGL fractionation and storage services at our facilities near Conway, Kansas, using various fee based contractual arrangements where we receive a fee or fees based on actual or contracted volumetric measures.

Fractionation Contracts

The fee-based fractionation contracts at our Conway facility generate revenues based on the volumes of mixed NGLs fractionated and the per-unit fee charged. The per-unit fee is generally subject to adjustment for changes in certain operating expenses, including natural gas, electricity and labor costs, which are the principal variable costs in NGL fractionation. As a result, we are generally able to pass through increases in those operating expenses to our customers. However, under one of our fractionation contracts, there is a cap on the per-unit fee and, under current natural gas market conditions, we are not able to pass through the full amount of increases in variable expenses to this customer. In order to mitigate the fuel price risk with respect to our purchases of natural gas needed to perform under this contract, upon the closing of our IPO offering in August 2005, Williams transferred to us a contract for the purchase of a sufficient quantity of natural gas from a wholly owned subsidiary of Williams at a fixed price to satisfy our fuel requirements under this fractionation contract. Williams paid the full costs associated with entering into this contract prior to assigning the contract to us upon closing of our IPO. The fair value of this gas purchase contract was recorded as an equity contribution to us by Williams. This gas purchase contract will terminate on December 31, 2007 to correspond with the expected termination of the related fractionation agreement. Pursuant to the terms of this agreement we provided notice of termination to this customer in July 2005. If we are unable to negotiate a new agreement with this customer upon such termination, we believe that we could contract with other potential customers to replace a significant portion of these volumes.

Two contracts with remaining terms of approximately three and five years account for most of our fractionation revenues. The revenues we generate under fractionation contracts at our Conway facility generally are not directly affected by changing commodity prices. However, to the extent a sustained decline in commodity prices received by our customers results in a decline in their production volumes, our revenues from these contracts could be reduced. One of our customers has the contractual right, on a month-to-month basis, to deliver its mixed NGLs elsewhere. Its decision on whether to ship its products to the Mid-Continent region or another region depends on supply and demand in the respective regions and the current price being paid for fractionated products in each region.

Storage Contracts

Substantially all our storage contracts are on a firm basis, pursuant to which our customers pay a demand charge for a contracted volume of storage capacity, including injection and withdrawal rights. The majority of our storage revenues are from three contracts with remaining terms between four and fourteen years. The terms of our remaining storage contracts are typically one year or less. In addition, we also enter into contracts for fungible product storage in increments of six months, three months and one month.

For storage contracts of one year or less, we require our customers to remit the full contract price at the time the contract is signed, which reduces our overall credit risk. Most of our contracts of one year or less are on a fixed price basis. We base our longer-term contracts on a percentage of our published price of storage in our Conway facilities and adjust these prices annually.

We offer our customers four types of storage contracts: single product fungible, two product fungible, multi-product fungible and segregated product storage. In addition to the fees we charge for contracted storage, we also receive fees for overstorage. Overstorage is all barrels held in a customer s inventory in excess of that customer s contractual storage rights, calculated on a daily basis.

Because we typically contract for periods of one year or longer, our business is less susceptible to seasonal variations. However, spot and future NGL market prices can influence demand for storage. When the market for propane and other NGLs is in backwardation, the demand for storage capacity of our Conway facilities may decrease. While this would not impact our long-term leases of storage capacity, our customers could become less likely to enter into short-term storage contracts.

Operating Supply Management

We also generate revenues by managing product imbalances at our Conway facilities. In response to market conditions, we actively manage the fractionation process to optimize the resulting mix of products. Generally, this process leaves us with a surplus of propane volumes and a deficit of ethane volumes. We sell the surplus propane and make up the ethane deficit through open-market purchases. We refer to these transactions as product sales and product purchases. In addition, product imbalances may arise due to measurement variances that occur during the routine operation of a storage cavern. These imbalances are realized when storage caverns are emptied. We are able to sell any excess product volumes for our own account, but must make up product deficits. The flexibility we enjoy as operator of the storage facility allows us to manage the economic impact of deficit volumes by settling deficit volumes either from our storage inventory or through opportunistic open-market purchases.

Historically, we effected these product sales and purchases with third parties. However, in December of 2004, we began to effect these purchases and sales with a subsidiary of Williams. If this arrangement with the Williams subsidiary were terminated, we believe we could once again transact with third parties.

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Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make significant estimates and assumptions. The selection of these policies has been discussed with the Audit Committee. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Impairment of Long-Lived Assets and Investments

We evaluate our long-lived assets and investments for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of certain long-lived assets or that the decline in value of an investment is other-than-temporary.

During 2004, we performed an impairment review of our 40 percent equity investment in Discovery because of Williams planned purchase of an additional interest in Discovery at an amount below our current carrying value. We estimated the fair value of our investment based on a probability-weighted analysis that considered a range of expected future cash flows and earnings, EBITDA multiples and the distribution yields for master limited partnerships (MLP). Based upon our analysis we concluded that our investment in Discovery experienced an other-than-temporary decline in value. As a result, we recorded an 8 percent, or $13.5 million, impairment of this investment to its estimated fair value at December 31, 2004 (see Note 6 of Notes to Consolidated Financial Statements). Our computations utilized judgments and assumptions in the following areas:

- estimated future volumes and rates;
- the net present value of the expected future cash flows;
- potential proceeds from a sale to an existing MLP based on an acquirer s estimated distribution and earnings impact; and
- expected proceeds from our planned initial public offering.

Our projections are highly sensitive to changes in the above assumptions. The estimated cash flows from the various scenarios ranged from approximately $28.0 million above to approximately $20.0 million below our estimated fair value at December 31, 2004.

Accounting for Asset Retirement Obligations

We record asset retirement obligations for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset in the period in which it is incurred if a reasonable estimate of fair value can be made. At December 31, 2005, we have an accrued asset retirement obligation liability of $762,000 for estimated retirement costs associated with the abandonment of our Conway underground storage caverns and brine ponds in accordance with KDHE regulations. This estimate is based on the assumption that the abandonment occurs in 50 years. If this assumption were changed to 30 years, the recorded asset retirement obligation would increase by approximately $2.6 million. Our estimate utilizes judgments and assumptions regarding the costs to abandon a well bore and the timing of abandonment. Please read Note 7 of Notes to Consolidated Financial Statements.

Environmental Remediation Liabilities

We record liabilities for estimated environmental remediation liabilities when we assess that a loss is probable and the amount of the loss can be reasonably estimated. At December 31, 2005, we have an accrual for estimated environmental remediation obligations of $5.4 million. This remediation accrual is revised, and our associated income is affected, during periods in which new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. We base liabilities for environmental remediation upon our assumptions and estimates regarding what remediation work and post-remediation monitoring will be required and the costs of those efforts, which we develop from information obtained from outside consultants and from discussions with the applicable

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governmental authorities. As new developments occur or more information becomes available, it is possible that our assumptions and estimates in these matters will change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarter or annual period. During 2004, we purchased an insurance policy covering some of our environmental liabilities. Please read Environmental and Note 13 of Notes to Consolidated Financial Statements for further information.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2005. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	2005	% Change from 2004(1)	2004	% Change from 2003(1)	2003
			(Dollars in thousands)		
Revenues	$ 51,769	+26%	$ 40,976	+45%	$ 28,294
Costs and expenses:					
Operating and maintenance expense	25,111	-30%	19,376	-39%	13,960
Product cost	11,821	-78%	6,635	NM	1,263
Depreciation and accretion	3,619	+2%	3,686	+1%	3,707
General and administrative expense	5,323	-104%	2,613	-44%	1,813
Taxes other than income	700	+2%	716	-12%	640
Other, net	(6)	-93%	(91)	-32%	(133)
Total costs and expenses	46,568	-41%	32,935	-55%	21,250
Operating income	5,201	-35%	8,041	+14%	7,044
Equity earnings Discovery	8,331	+85%	4,495	+30%	3,447
Impairment of investment in Discovery		+100%	(13,484)	NM	
Interest expense	(8,238)	+34%	(12,476)	-199%	(4,176)
Interest income	165	+100%		-%	
Income (loss) before cumulative effect of change in accounting principle	5,459	+141%	(13,424)	NM	6,315
Cumulative effect of change in accounting principle	(628)	NM		+100%	(1,099)
Net income (loss)	$ 4,831	+136%	$ (13,424)	NM	$ 5,216

(1) + = Favorable Change; - = Unfavorable Change; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

2005 vs. 2004

Revenues increased $10.8 million, or 26 percent, due primarily to higher revenues in our NGL Services segment reflecting increased product sales volumes and higher storage revenues, slightly offset by lower revenue in our Gathering and Processing segment due to Hurricanes Katrina and Rita and the 2004 recognition of a $950,000 settlement of a contractual volume deficiency provision.

Operating and maintenance expense increased $5.7 million, or 30 percent, due primarily to larger product imbalance valuation adjustments and higher fuel and power costs recognized by our NGL Services segment in 2005 as compared to 2004.

Product cost increased $5.2 million, or 78 percent, directly related to the increase in product sales volumes in our NGL Services segment.

General and administrative expense increased $2.7 million, or 104 percent, due primarily to the increased costs of being a publicly-traded partnership. These costs included $1.1 million for audit fees, tax return preparation, director fees, and registration and transfer agent fees, $0.7 million for direct and specific charges allocated, by Williams, for accounting, legal, and other support, $0.6 million for business development, and $0.3 million for other various expenses.

Operating income decreased $2.8 million, or 35 percent, due primarily to higher operating and maintenance expense in our NGL Services segment, higher general and administrative expenses and lower revenues in our Gathering and Processing segment, partially offset by higher storage revenues in our NGL Services segment.

Equity earnings from Discovery increased $3.8 million. This increase is discussed in detail in the Results of Operations Gathering and Processing section.

The impairment of our investment in Discovery is the result of our analysis pursuant to which we concluded that we had experienced an other than temporary decline in the value of our investment in Discovery as described above in Critical Accounting Policies and Estimates Impairment of Long-Lived Assets and Investments.

Interest expense decreased $4.2 million, or 34 percent, due primarily to the forgiveness of the advances from Williams in conjunction with the closing of the IPO on August 23, 2005.

The Cumulative effect of change in accounting principle of $0.6 million in 2005 relates to our December 31, 2005 adoption of Financial Accounting Standards Board Interpretation (FIN) No. 47. Please read Note 7 of Notes to Consolidated Financial Statements.

2004 vs. 2003

Revenues increased $12.7 million, or 45 percent, due mainly to higher revenues in our NGL Services segment, reflecting higher product sales volumes and storage rates.

Operating and maintenance expenses increased $5.4 million, or 39 percent, due primarily to increased costs to comply with KDHE requirements at NGL Services Conway facilities. Product costs increased $5.4 million, from $1.3 million, due to the increase in product sales.

General and administrative expenses increased $0.8 million, or 44 percent, due primarily to an increase in allocated general and administrative expenses from Williams reflecting increased corporate overhead costs within the Williams organization. These increased costs related to various corporate initiatives and Sarbanes-Oxley Act compliance efforts within Williams.

The impairment of our investment in Discovery is the result of our analysis pursuant to which we concluded that we had experienced an other than temporary decline in the value of our investment in Discovery as described in Results of Operations Gathering and Processing section.

Interest expense increased $8.3 million, from $4.2 million, due primarily to the cash advanced by Williams in December 2003 to fund our $101.6 million share of a cash call by Discovery to repay its outstanding debt.

The Cumulative effect of change in accounting principle of $1.1 million in 2003 relates to our January 1, 2003 adoption of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations. Please read Note 7 of Notes to Consolidated Financial Statements.

Results of operations Gathering and Processing

The Gathering and Processing segment includes the Carbonate Trend gathering pipeline and our 40 percent ownership interest in Discovery.

	2005	2004	2003
		(In thousands)	
Segment revenues	$ 3,515	$ 4,833	$ 5,513
Costs and expenses:			
Operating and maintenance expense	714	572	379
Depreciation	1,200	1,200	1,200
General and administrative expense-direct	2		
Total costs and expenses	1,916	1,772	1,579
Segment operating income	1,599	3,061	3,934
Equity earnings Discovery	8,331	4,495	3,447
Impairment of investment in Discovery		(13,484)	
Segment profit (loss)	$ 9,930	$ (5,928)	$ 7,381

Carbonate Trend

2005 vs. 2004

Segment revenues decreased $1.3 million, or 27 percent, due primarily to a 29 percent decline in average daily gathered volumes between 2005 and 2004 and the absence of $950,000 of revenue from the settlement of a contractual volume deficiency payment recognized in 2004, partially offset by $452,000 of revenue from the settlement of a contractual volume deficiency payment recognized in 2005.

The decline in average daily gathered volumes was caused by normal reservoir depletion, reduced capacity experienced at a third-party onshore treating plant in April 2005 and the temporary shutdowns for Hurricane Dennis in July 2005 and Hurricane Katrina in August 2005. The overall impact of this decline in gathered volumes on gathering revenue was approximately $1.1 million. This decline in gathered volumes was partially offset by a 11 percent higher average gathering rate causing a $300,000 increase in gathering revenue. The increase in the average gathering rate was due to a customer s annual election in 2005 under a bundled rate provision within its contract.

Operating and maintenance expense increased $142,000, or 25 percent, due to $72,000 increased costs for inhibitor chemicals and internal pipeline corrosion inspection, and $70,000 related to insurance costs. These increases were offset partially by increased painting expense in 2004.

Segment operating income decreased $1.5 million, or 48 percent, due primarily to the lower revenues discussed above.

2004 vs. 2003

Segment revenues decreased $0.7 million, or 12 percent, due primarily to a 26 percent decline in gathering volumes in 2004, largely offset by the recognition in 2004 of a $950,000 settlement of a contractual volume deficiency provision. Gathering volumes declined in 2004 due to lower production from connected wells that was not offset by new production coming online.

Operating and maintenance expenses increased $0.2 million due to additional costs for contractor services.

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Discovery

Discovery is accounted for using the equity method of accounting. As such, our interest in Discovery s net operating results is reflected as equity earnings in our Consolidated Statements of Operations. Due to the significance of Discovery s equity earnings to our results of operations, the following discussion addresses in greater detail the results of operations for 100 percent of Discovery.

	2005	2004	2003
		(In thousands)	
Revenues	$ 122,745	$ 99,876	$ 103,178
Costs and expenses, including interest:			
Product cost and shrink replacement	64,467	45,355	42,914
Operating and maintenance expense	10,165	17,854	15,829
General and administrative expense	2,053	1,424	1,400
Depreciation and accretion	24,794	22,795	22,875
Interest expense (income)	(1,685)	(550)	9,611
Other expenses, net	2,123	1,328	1,501
Total costs and expenses	101,917	88,206	94,130
Net income before cumulative effect of change in accounting principle	$ 20,828	$ 11,670	$ 9,048
Williams Partners 40% interest	$ 8,331	$ 4,668	$ 3,619
Capitalized interest amortization		(173)	(172)
Equity earnings per our Consolidated Statement of Operations	$ 8,331	$ 4,495	$ 3,447

2005 vs. 2004

Revenues increased $22.9 million, or 23 percent, due primarily to higher NGL product sales from marketing of customers NGLs, fractionation revenue, processing revenue and average per-unit NGL sales prices, partially offset by lower NGL sales volumes. The significant components of this increase include the following.

Product sales increased $31.6 million for the NGL sales related to third-party processing customers election to have Discovery market their NGLs for a fee under an option in their contracts. These sales were offset by higher associated product costs of $31.6 million discussed below.

Processing and fractionation revenues increased $6.8 million including $3.9 million in additional volumes related to the TGP and TETCO open seasons discussed previously, $2.9 million related to an increase in the fractionation rate for increased natural gas fuel cost pass through, and other increases related to new volumes from the Front Runner prospect that came on line in the first quarter of 2005.

Gathering revenues increased $2.1 million due primarily to a $1.4 million deficiency payment received in 2005 related to a volume shortfall under a transportation contract, $0.4 million related to an increase in volumes and $0.3 million related to a 25 percent higher average gathering rate associated with new volumes from the Front Runner prospect.

Partially offsetting these increases were the following:

Product sales decreased $4.9 million as a result of lower sales of excess fuel and shrink replacement gas in 2005. During the first half of 2004 increased natural gas prices made it more economical for Discovery s customers to bypass the processing plant rather than process the gas, leaving Discovery with higher levels of excess fuel and replacement gas in 2004 than 2005.

Product sales also decreased approximately $16.0 million as a result of 36 percent lower NGL sales volumes following Hurricanes Katrina and Rita, partially offset by a $5.0 million increase associated with a 17 percent higher average sales prices.

Transportation revenues decreased $0.6 million due primarily to lower condensate transportation volumes. Higher average natural gas transportation volumes were partially offset by a lower average natural gas transmission rate.

Other revenues declined $1.1 million due largely to lower platform rental fees.

Product cost and shrink replacement increased $19.1 million, or 42 percent, due primarily to:

$31.6 million increased purchase costs for the two processing customers who elected to have Discovery market their NGLs; and

$3.4 million resulting from higher average per-unit natural gas prices.

Partially offsetting these increases were the following:

$11.0 million lower costs related to reduced processing activity in 2005; and

$4.9 million lower cost associated with sales of excess fuel and shrink natural gas.

Operating and maintenance expense decreased $7.7 million, or 43 percent, due primarily to a $10.7 million credit related to amounts previously deferred for net system gains from 2002 through 2004 that were reversed following the acceptance in 2005 of a filing with the FERC, partially offset by $1.2 million higher utility costs, $1.0 million of uninsured damages caused by Hurricane Katrina, and $0.8 million other miscellaneous operational costs.

General and administrative expense increased $0.6 million, or 44 percent, due primarily to an increase in the management fee paid to Williams related to Discovery s market expansion project and additions of other facilities. For a discussion of Discovery s recently completed market expansion project, please read Business The Discovery Assets Discovery Natural Gas Pipeline System.

Depreciation and accretion expense increased $2.0 million, or 9 percent, due primarily to the completion of a pipeline connection to the Front Runner prospect in late 2004.

Interest income increased $1.1 million, due primarily to increases in interest-bearing cash balances during early 2005 period when cash flows from operations were being retained by Discovery.

Other expenses, net increased $0.8 million, or 60 percent, due primarily to a non-cash foreign currency transaction loss from the revaluation of restricted cash accounts denominated in Euros. These restricted cash accounts were established from contributions made by Discovery s members, including us, for the construction of the Tahiti pipeline lateral expansion project.

Net income increased $9.2 million, or 78 percent, due primarily to the $10.7 million reserve reversal, $8.9 million increased revenue from gathering, processing and fractionation services and $1.1 million higher interest income, partially offset by $3.5 million lower product sales margins, $3.0 million higher other operating and maintenance expense, $0.6 million higher general and administrative expense, $2.0 million higher depreciation and accretion, and $0.8 higher other expense including the foreign currency transaction loss.

2004 vs. 2003

The $3.3 million, or 3 percent, decrease in revenues resulted primarily from lower fuel and shrink replacement gas sales in 2004 and lower NGL sales volumes, partially offset by higher average per-unit NGL sales prices. The significant components of this decrease consisted of the following:

Increasing gas prices during some months of 2003 made it more economical for Discovery s customers to bypass the processing plant rather than to process the gas, leaving Discovery with higher levels of excess fuel and shrink replacement gas in 2003 than 2004. This excess natural gas was sold in the market in 2003, which resulted in $5.1 million of lower revenues in 2004.

Transportation volumes declined 6 percent due to production declines and a temporary interruption of service because of an accidental influx of seawater in a lateral while putting in place a subsea connection to a wellhead. These lower volumes resulted in a decrease in fee-based revenues, including $2.7 million from gathering and transportation, $2.2 million from fee-based processing and $0.2 million from fractionation, for a total of $5.1 million.

Other revenues decreased $1.5 million due to a $0.9 million decrease in offshore platform production handling fees related to lower natural gas production volumes and $0.8 million received in connection with the resolution of a condensate measurement and ownership allocation issue in 2003.

NGL sales increased $8.5 million due to a 26 percent increase in average sales prices, which were slightly offset by a 2 percent decrease in sales volumes.

Product cost and shrink replacement gas costs increased by $2.4 million, or 6 percent, primarily due to higher average gas prices. Operating and maintenance expense increased $2.0 million, or 12 percent, from 2003 due primarily to $1.2 million of costs for a routine compressor overhaul and $1.3 million of costs to correct a non-routine temporary interruption of service due to an accidental influx of seawater in our offshore pipeline. These increases were partially offset by lower miscellaneous operating expenses.

Interest expense decreased $9.6 million due to the repayment of $253.7 million of outstanding debt in December 2003. Other expense, net decreased $0.7 million due primarily to $0.6 million of income earned on the short term investing of excess cash.

Net Income increased $2.6 million, or 29 percent, due primarily to $9.6 million lower interest expense, $0.7 million lower other expense, partially offset by $3.3 million lower revenue, $2.4 million higher product cost and shrink expense and $2.0 million higher operating and maintenance expense.

Outlook for 2006

We currently estimate that we will incur $3.4 million to $4.6 million of maintenance expenditures for Carbonate Trend during 2006 for restoration activities related to the partial erosion of the pipeline overburden caused by Hurricane Ivan in September 2004. Under our omnibus agreement, Williams agreed to reimburse us for the cost of these restoration activities. In connection with these restoration activities, the Carbonate Trend pipeline may experience a temporary shut down. We estimate that this shut down could reduce our cash flows from operations, excluding the maintenance expenditures, by approximately $0.2 million to $0.3 million.

Throughput volumes on Discovery s pipeline system and our Carbonate Trend pipeline are an important component of maximizing our profitability. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time. Accordingly, to maintain or increase throughput levels on these pipelines and the utilization rate of Discovery s natural gas plant and fractionator, we and Discovery must continually obtain new supplies of natural gas.

In 2006, recompletions and workovers may not offset production declines from the wells currently connected to the Carbonate Trend pipeline.

We anticipate continued throughput from the TGP and TETCO open season volumes through the first quarter of 2006. Discovery is discussing retaining some of this gas on a long-term basis and will compete with several other plants in the area for this business.

We anticipate lower gathered volumes from Discovery s pre-hurricane sources throughout 2006. The 2005 hurricanes caused a significant disruption in our customer s normal operations including critical recompletion and drilling activity necessary to sustain and improve their production levels.

With the current oil and natural gas price environment, drilling activity across the shelf and the deepwater of the Gulf of Mexico has been robust. However, the availability of specialized rigs necessary to drill in the deepwater areas, such as those in and around Discovery s gathering areas,

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limits producers ability to bring identified reserves to market quickly. This will prolong the timeframe over which these reserves will be developed. We expect Discovery to be successful in competing for a portion of these new volumes.

Late in the first quarter of 2006, Discovery expects to connect a new well in ATP s Gomez prospect, with an estimated initial volume of 35,000 MMBtu/d. Capital to connect this new well will be provided by others. This initial flow date was delayed due to the hurricane repair activities.

Results of operations NGL Services

The NGL Services segment includes our three NGL storage facilities near Conway, Kansas and our undivided 50 percent interest in the Conway fractionator.

	2005	2004	2003
		(In thousands)	
Segment revenues	$ 48,254	$ 36,143	$ 22,781
Costs and expenses:			
Operating and maintenance expense	24,397	18,804	13,581
Product cost	11,821	6,635	1,263
Depreciation and accretion	2,419	2,486	2,507
General and administrative expense direct	1,068	535	421
Other, net	694	625	507
Total costs and expenses	40,399	29,085	18,279
Segment profit	$ 7,855	$ 7,058	$ 4,502

2005 vs. 2004

Segment revenues increased $12.1 million, or 34 percent, due primarily to higher product sales, storage and fractionation revenues. The significant components of the increase include the following:

Product sales were $5.0 million higher due primarily to the sale of surplus propane volumes created through our product optimization activities. This increase was partially offset by the related increase in Product cost.

Storage revenues increased $5.0 million due primarily to higher average per-unit storage rates for 2005 and higher storage volumes from additional short-term storage leases caused by the reduced demand for propane due to unusually warm temperatures in the early winter months of 2005 and an overall increase in butane and storage volumes. The published rate for one-year storage contracts increased 67 percent on April 1, 2004, primarily reflecting the pass through to customers of increased costs to comply with KDHE regulations. The storage volumes in the remaining quarters of 2004 initially declined due to these higher storage rates. During 2005, the volumes returned to more normal levels.

Fractionation revenues increased $1.7 million due primarily to a 17 percent increase in the average fractionation rate related to the pass through to customers of increased fuel and power costs and 4 percent higher volumes in 2005.

Other revenues increased $0.4 million due to increased railcar loadings in 2005.

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The following table summarizes the major components of operating and maintenance expense that are discussed in detail below.

	2005	2004	2003
		(In thousands)	
Operating and maintenance expense:			
Salaries and benefits	$ 2,773	$ 2,740	$ 2,762
Outside services and other	7,458	8,240	3,843
Fuel and power	12,538	8,565	7,608
Product imbalance expense (income)	1,628	(741)	(632)
Total operating and maintenance expense	$ 24,397	$ 18,804	$ 13,581

Outside services and other decreased $0.8 million due to fewer storage cavern workovers in 2005 as compared to 2004. Also our estimated asset retirement obligation for the storage caverns was adjusted in 2005, reducing our operating expense by $0.5 million.

Fuel and power costs increased $4.0 million due primarily to a 33 percent increase in the average per-unit price for natural gas, which we are generally able to pass through to our customers. Fuel and Power cost also includes $2.0 million for the amortization of a natural gas purchase contract contributed to us by Williams at the closing of our IPO. Please read, Our Operations NGL Services Segment Fractionation Contracts.

Product imbalance expense increased $2.4 million due primarily to $3.0 million larger product imbalance valuation adjustments and $0.6 million other product losses, partially offset by a $1.2 million increase in product optimization gains due to a significantly higher spread between propane and ethane prices in 2005.

Product cost increased $5.2 million, or 78 percent, directly related to increased sales of surplus propane volumes created through our product optimization activities.

General and administrative expense direct increased $0.5 million, or 100 percent, due primarily to increased operational and technical support for these assets.

Segment profit increased $0.8 million, or 11 percent, due primarily to the $6.7 million higher storage and fractionation revenues and $0.4 million higher other revenues for increased railcar loadings in 2005, partially offset by $5.6 million higher operating and maintenance expense, $0.5 million higher general and administrative expense direct charges and $0.2 million decrease in product margin.

2004 vs. 2003

Revenues increased $13.4 million, or 59 percent, due primarily to increased product sales and storage revenues. The significant components of the increase consisted of the following:

Product sales were $6.9 million higher primarily due to the sale of surplus propane volumes created through our product optimization activities. Prior to 2003, the sale and purchase activities and related inventory associated with product optimization were conducted by another wholly owned subsidiary of Williams that was sold in 2002. We made no sales of surplus propane until 2004 as we transitioned to conducting these activities and accumulated inventory.

Storage revenues increased $3.7 million due to higher average per-unit storage rates, slightly offset by lower contracted storage volumes. The published rate for one-year storage contracts increased 67 percent on April 1, 2004 and primarily reflects the pass through of increased costs to comply with KDHE regulations.

During 2004 we began offering product upgrading services for normal butane at our fractionator. This service contributed $1.7 million of fee revenues in 2004.

Product costs increased $5.4 million, from $1.3 million, directly related to increased product sales. Operating and maintenance expenses increased by $5.2 million, or 38 percent, primarily from higher maintenance expenses and fuel costs. The significant components consisted of the following:

Outside services and other expenses increased $4.4 million due to new storage cavern workover activity related to KDHE requirements.

Fuel expense increased $1.0 million due to an 18 percent increase in the average price of natural gas.

Segment profit increased $2.6 million, or 56.8 percent, due primarily to higher storage and fractionation revenue of $4.5 million, favorable product sales margins of $1.5 million, $1.7 million higher other fee revenues partially offset by $5.2 million higher operating and maintenance expense.

Outlook for 2006

We expect volumes fractionated for our customers at the Conway fractionator to continue averaging 40,000 bpd. Currently, commodity prices in the Mid-Continent region remain strong relative to commodity prices at the Mont Belvieu, Texas market hub, which minimizes the potential for volumes to be redirected to the Mont Belvieu market. We also expect to continue to produce income from the blending and segregation of various products.

During the third and fourth quarters of 2005 we experienced a significant increase in storage revenues from short-term contracts. We do not expect this increase to continue because the seasonal increase in retail propane sales began in the first quarter of 2006 and we are nearing the end of the storage contract year. We do not plan to increase storage fees in 2006.

We expect outside service costs to increase in 2006 due to the large number of cavern workovers planned for the first quarter of 2006. We expect outside service costs to continue at these increased levels throughout 2006 and 2007 to ensure that we meet the regulatory compliance requirement to complete cavern workovers before the end of 2008.

Financial Condition and Liquidity

Outlook for 2006

Prior to our IPO in August 2005, our sources of liquidity included cash generated from operations and funding from Williams. Our cash receipts were deposited in Williams bank accounts and all cash disbursements were made from these accounts. Thus, historically our financial statements have reflected no cash balances. Cash transactions handled by Williams for us were reflected in intercompany advances between Williams and us. Following our IPO, we maintain our own bank accounts but continue to utilize Williams personnel to manage our cash and investments.

We believe we have, or have access, to the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures, and quarterly cash distributions. We anticipate our 2006 sources of liquidity will include:

Cash generated from operations;

Cash distributions from Discovery;

Capital contributions from Williams pursuant to an omnibus agreement; and

Credit facilities, as needed.

We anticipate our more significant 2006 capital requirements to be:

Maintenance capital expenditures for our Conway assets;

Capital contributions to Discovery for its capital expenditure program;

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Working capital attributable to deferred revenues; and

Minimum quarterly distributions to our unitholders.

Discovery

Prior to our IPO, cash distributions from Discovery to its members required unanimous consent and no such distributions were made. Discovery s limited liability company agreement has been amended to provide for quarterly distributions of available cash. We expect future cash requirements for Discovery relating to working capital and maintenance capital expenditures to be funded from cash retained by Discovery at the closing of our IPO and from its own internally generated cash flows from operations. Growth or expansion capital expenditures for Discovery will be funded by either cash calls to its members, which requires unanimous consent of the members except in limited circumstances, or from internally generated funds. Prior to our IPO, Discovery made a distribution of approximately $43.8 million on August 22, 2005 to its existing members, representing about 75 percent of Discovery s retained cash. This distributed cash was associated with Discovery s operations prior to our IPO and, accordingly, we did not receive any portion of this distribution.

Prospectively, Discovery expects to make quarterly distributions of available cash to its members instead of retaining all cash from operations. Accordingly, January 31, 2006, pursuant to the terms of its limited liability company agreement, Discovery made an $11.0 million distribution of available cash to its members. Our 40 percent share of this distribution was $4.4 million.

Capital Contributions from Williams

Capital contributions from Williams required under the omnibus agreement consist of the following:

Indemnification of environmental and related expenditures for a period of three years (for certain of those expenditures) up to $14 million, which includes between $3.4 million and $4.6 million for the restoration activities due to the partial erosion of the Carbonate Trend pipeline overburden by Hurricane Ivan, approximately $3.1 million for capital expenditures related to KDHE-related cavern compliance at our Conway storage facilities, and approximately $1.0 million for our 40 percent share of Discovery s costs for marshland restoration and repair or replacement of Paradis emission-control flare.

An annual credit for general and administrative expenses of $3.9 million in 2005 ($1.4 million pro-rated for the portion of the year from August 23 to December 31), $3.2 million in 2006, $2.4 million in 2007, $1.6 million in 2008 and $0.8 million in 2009.

Up to $3.4 million to fund our 40 percent share of the expected total cost of Discovery s Tahiti pipeline lateral expansion project in excess of the $24.4 million we contributed during September 2005.

Credit Facilities

On May 20, 2005, Williams amended its $1.275 billion revolving credit facility, which is available for borrowings and letters of credit, to allow us to borrow up to $75 million under the Williams facility. Borrowings under this facility mature on May 3, 2007. Our $75 million borrowing limit under Williams revolving credit facility is available for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. At December 31, 2005, letters of credit totaling $378 million had been issued on behalf of Williams by the participating institutions under this facility and no revolving credit loans were outstanding. See Note 11 of the Notes to Consolidated Financial Statements for additional information.

We also have a $20 million revolving credit facility with Williams as the lender. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility will mature on May 3, 2007. We are required to reduce all borrowings under this facility to zero for a period of at least 15 consecutive days once

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each 12-month period prior to the maturity date of the facility. For 2005, we had no borrowings under the working capital credit facility. See Note 11 of Notes to Consolidated Financial Statements for additional information.

Capital Requirements

The natural gas gathering, processing and transportation, and NGL fractionation and storage businesses are capital-intensive, requiring investment to upgrade or enhance existing operations and comply with safety and environmental regulations. The capital requirements of these businesses consist primarily of:

Maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives; and

Expansion capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade plant or pipeline capacity and to construct new plants, pipelines and storage facilities.

We estimate that maintenance capital expenditures for the Conway assets will be approximately $9.0 million for 2006, including approximately $2.3 million to be spent in connection with the installation of wellhead control equipment and well meters and KDHE-related cavern compliance. In the omnibus agreement, Williams agreed to reimburse us for the cost of these expenditures subject to a three-year time limitation from the IPO closing date, August 23, 2005, and an overall omnibus agreement limitation of $14 million. Additionally, capital expenditures include $3.2 million related to workovers that include the installation of cavern liners. The remaining amount consists of various smaller maintenance projects.

We estimate that maintenance capital expenditures for 100 percent of Discovery will be approximately $2.7 million for 2006. We expect Discovery will fund its maintenance capital expenditures through cash flow from operations.

We estimate that expansion capital expenditures for 100 percent of Discovery will be approximately $37.6 million for 2006. This amount includes $2.0 million for marshland restoration costs related to the initial construction of the Discovery pipeline, $27.4 million for the ongoing construction of the Tahiti pipeline lateral expansion project, $8.0 million related to a cogeneration project that we expect will have a favorable impact on Discovery s operating expenses of approximately $1.5 to $2.0 million annually, and $0.2 million for other efficiency projects. We expect Discovery will fund the $2.0 million for marshland restoration through retained cash flow from operations or capital contributions from its members. In either case, our 40 percent share of marshland restoration costs will be reimbursed by Williams pursuant to our omnibus agreement. We expect Discovery will fund the $27.4 million for the Tahiti pipeline lateral expansion project from the amounts escrowed for this project in September 2005 and capital contributions from its members including approximately $4.0 million of cost that cannot, by agreement, be funded from the escrowed funds. Our 40 percent share of this $4.0 million cost will be reimbursed by Williams pursuant to our omnibus agreement. Total construction costs of this project are expected to be approximately $69.5 million and we anticipate that the assets will be placed in service in 2007. We expect Discovery will fund the $8.0 million for the cogeneration project with capital contributions from its members, provided it is approved by the members, including us.

Working Capital Attributable to Deferred Revenues

We require cash in order to continue providing services to our storage customers who prepaid their annual storage contracts in April 2005. The storage year for customer contracts at our Conway storage facility runs from April 1 of a year to March 31 of the following year. We typically receive payment for these one-year contracts in advance in April after the beginning of the storage year and recognize the associated revenue over the course of the storage year. As of December 31, 2005, our deferred storage revenue is $3.4 million. We retained a portion of the proceeds from our IPO for working capital purposes associated with this deferred revenue.

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Cash Distributions to Unitholders

We paid a quarterly distribution of $5.0 million ($.35 per unit) to common and subordinated unitholders and the general partner interest on February 14, 2006. We intend to make minimum quarterly distributions totaling $5.0 million to the extent we have sufficient cash from operations after establishment of cash reserves.

Results of Operations Cash Flows

Williams Partners L.P.

	2005	2004	2003
		(In thousands)	
Net cash provided by operating activities	$ 1,893	$ 2,703	$ 6,644
Net cash used by investing activities	(28,088)	(1,534)	(102,810)
Net cash provided (used) by financing activities	33,034	(1,169)	96,166

The $0.8 million decrease in net cash provided by operating activities in 2005 as compared to 2004 is due primarily to:

$2.8 million related to trade accounts receivable at August 22, 2005 that were not included in the contribution of net assets to us;

$2.3 million related to decreases in the Conway product imbalance liability largely resulting from settlement activity in the fourth quarter of 2005; and

$1.0 million lower operating income, adjusted for non-cash expenses.

These decreases were largely offset by:

$4.2 million in lower interest expense due to the forgiveness by Williams of advances to us at the closing of our IPO; and

a $1.3 million increase in distributed earnings from Discovery.

The decrease of $3.9 million in net cash provided by operating activities in 2004 as compared to 2003 reflects an increase of $8.3 million in interest expense in 2004 related primarily to the funding of our $101.6 million share of a Discovery cash call discussed below. This decrease in net cash provided by operating activities was partially offset by changes in working capital, including a $2.7 million increase in accounts payable. The increase in accounts payable was due to a $1.6 million accrual for spot ethane purchases in December 2004 and a $1.0 million higher accrual for power costs at the end of 2004 as compared to 2003.

Net cash used by investing activities includes maintenance capital expenditures in our NGL Services segment. In addition, 2005 includes our capital contribution of $24.4 million to Discovery for construction of the Tahiti pipeline lateral expansion project. Net cash used by investing activities in 2003 also includes our $101.6 million capital contribution to Discovery for the repayment of Discovery s outstanding debt in December 2003.

Net cash provided by financing activities in 2005 includes the cash flows related to our IPO on August 23, 2005. These consisted of $100.2 million in net proceeds from the sale of the units, a $58.8 million distribution to Williams and the payment of $4.3 million in expenses associated with our IPO. Net cash provided (used) by financing activities for 2005 and 2004 also includes the pass through of $3.7 million and $1.2 million, respectively, of net cash flows to Williams prior to August 23, 2005, under its cash management program. Following the closing of our IPO on August 23, 2005, we no longer participate in Williams cash management program, and our net cash flows no longer pass through to Williams. The 2005 period also includes $2.1 million of distributions paid to unitholders and $1.6 million in indemnifications and reimbursements received from Williams pursuant to the omnibus agreement.

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Net cash provided by financing activities in 2003 includes advances from Williams to fund our $101.6 million share of a Discovery cash call discussed above. The remaining 2003 financing cash flows represent the pass through of our net cash flows to Williams under its cash management program as described above.

Discovery 100 percent

	2005	2004	2003
		(In thousands)	
Net cash provided by operating activities	$ 30,814	$ 35,623	$ 44,025
Net cash used by investing activities	(65,997)	(39,115)	(12,073)
Net cash provided by financing activities	1,339		409

Net cash provided by operating activities decreased $4.8 million in 2005 as compared to 2004 due primarily to expenditures incurred for repairs following Hurricane Katrina that have not yet been reimbursed by Discovery s insurance carrier. The 2005 use of cash related to accounts receivable included a $24.6 million outstanding receivable from Power for the marketing activities associated with the TGP and TETCO open seasons discussed above; this was offset by a similar change in accounts payable for a balance due to the shippers of TGP and the TETCO. The 2005 use of cash related to accounts receivable also included other increases in customers outstanding balances of $8.6 million. The 2005 source of cash related to accounts payable also included a $7.7 million overpayment by a customer.

Net cash provided by operating activities decreased $8.4 million in 2004 as compared to 2003 due primarily to the favorable impact in 2003 of improved accounts receivable collections. Working capital levels remained more constant in 2004 as compared to 2003. As a result, net cash provided by operating activities in 2004 did not include significant amounts from changes in working capital and reflected the return to more normal levels.

During 2005, net cash used by investing activities included $44.6 million to fund escrow accounts for the Tahiti pipeline lateral project and related interest income and $21.4 million of capital expenditures for (1) the completion of the Front Runner and market expansion projects, (2) the initial expenditures for the Tahiti project, and (3) the purchase of leased compressors at the Larose processing plant. During 2004, net cash used by investing activities was primarily used for the construction of a gathering lateral to connect our pipeline system to the Front Runner prospect. During 2003, net cash used for investing activities was primarily for the purchase of a 12 gathering pipeline ($3.5 million) and initial capital expenditures incurred for the construction of a gathering lateral to connect to Discovery s pipeline system to the Front Runner prospect ($4.5 million).

During 2005, net cash provided by financing activities included capital contributions totaling $48.3 million from our members for the construction of the Tahiti pipeline lateral expansion, the distribution of cash associated with our operations prior to our IPO of $43.8 million and a quarterly distribution to members in the fourth quarter of 2005 of $3.2 million. During 2003, Discovery s members made capital contributions of $254.1 million in response to a cash call by Discovery. Discovery used these contributions to retire its outstanding debt of $253.7 million.

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Contractual Obligations

A summary of our contractual obligations as of December 31, 2005, is as follows (in thousands):

	2006	2007-2008	2009-2010	2011+	Total
Notes payable/long-term debt	$	$	$	$	$
Capital leases					
Operating leases	30	55	10		95
Purchase obligations	5,135	2,928	240	120(a)	8,423
Other long term liabilities					
Total	$ 5,165	$ 2,983	$ 250	$ 120	$ 8,518

(a) Year 2011 represents one year of payments associated with an operating agreement whose term is tied to the life of the underlying gas reserves.

Our equity investee, Discovery, also has contractual obligations for which we are not contractually liable. These contractual obligations, however, will impact Discovery s ability to make cash distributions to us. A summary of Discovery s total contractual obligations as of December 31, 2005, is as follows (in thousands):

	2006	2007-2008	2009-2010	2011+	Total
Notes payable/long-term debt	$	$	$	$	$
Capital leases					
Operating leases	854	1,712	1,716	4,109	8,391
Purchase obligations(a)	30,807	23,488			54,295
Other long-term liabilities					
Total	$ 31,661	$ 25,200	$ 1,716	$ 4,109	$ 62,686

(a) With the exception of $3.4 million of 2006 outstanding purchase orders, all other amounts are Tahiti-related expenditures that will be funded from the amounts escrowed for this project in September 2005 and capital contributions from members including us. Please read Financial Condition and Liquidity Outlook for 2006 .

Effects of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the three-year period ended December 31, 2005. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by specific price changes in natural gas and NGLs. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Regulatory Matters

As of December 31, 2005, Discovery had deferred amounts of $6 million relating to retained system gas gains and the over-recovery of lost and unaccounted-for gas on the Discovery system. Please read Note 7 Rate and Regulatory Matters and Contingent Liabilities Rate and Regulatory Matters to the Discovery Producer Services LLC Consolidated Financial Statements included herein. Certain shippers challenged Discovery s right to retain these gains. FERC requested and received from Discovery additional information regarding both lost and unaccounted-for-volumes and gas gains. Discovery responded to the information

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request and on October 31, 2005, the FERC accepted the filing and no requests for rehearing were filed. As a result, we recognized the portion of this reserve for the period 2002 through 2004 of $10.7 million in 2005.

Discovery s natural gas pipeline transportation is subject to rate regulation by FERC under the Natural Gas Act. For more information on federal and state regulations affecting our business, please read Risk Factors and FERC Regulation elsewhere in this report.

Environmental

Our Conway storage facilities are subject to strict environmental regulation by the Underground Storage Unit within the Geology Section of the Bureau of Water of the KDHE under the Underground Hydrocarbon and Natural Gas Storage Program, which became effective on April 1, 2003.

We are in the process of modifying our Conway storage facilities, including the caverns and brine ponds, and we expect our storage operations will be in compliance with the Underground Hydrocarbon and Natural Gas Storage Program regulations by the applicable required compliance dates. In 2003, we began to complete workovers on approximately 30 to 35 salt caverns per year and install, on average, a double liner on one brine pond per year. The incremental costs of these activities is approximately $5.5 million per year to complete the workovers and approximately $900,000 per year to install a double liner on a brine bond. In response to these increased costs, we raised our storage rates in 2004 by an amount sufficient to preserve our margins in this business. Accordingly, we do not believe that these increased costs have had a material effect on our business or results of operations. We expect on average to complete workovers on each of our caverns every five to ten years and install double liners on each of our brine ponds every 18 years. The KDHE has also advised us that a regulation relating to the metering of NGL volumes that are injected and withdrawn from our caverns may be interpreted and enforced to require the installation of meters at each of our well bores. We have informed the KDHE that we disagree with this interpretation, and the KDHE has asked us to provide it with additional information. We estimate that the cost of installing a meter at each of our well bores at Conway West and Mitchell would be approximately $3.9 million over three years.

As of December 31, 2005, we had accrued environmental liabilities of $5.4 million related to four remediation projects at the Conway storage facilities. In 2004, we purchased an insurance policy that covers up to $5.0 million of remediation costs until an active remediation system is in place or April 30, 2008, whichever is earlier, excluding operation and maintenance costs and ongoing monitoring costs, for these four projects to the extent such costs exceed a $4.2 million deductible. The policy also covers costs incurred as a result of third party claims associated with then existing but unknown contamination related to the storage facilities. The aggregate limit under the policy for all claims is $25 million. In the omnibus agreement, Williams agreed to indemnify us for these remediation expenditures to the extent not recovered under the insurance policy, excluding costs of project management and soil and groundwater monitoring, and certain other environmental and related obligations arising out of or associated with the operation of the assets before the closing date of our IPO. There is an aggregate cap of $14.0 million on the total amount of indemnity coverage under the omnibus agreement, which will be reduced by actual recoveries under the environmental insurance policy. There is also a three-year time limitation from the IPO closing date, August 23, 2005. We estimate that the approximate cost of the project management and soil and groundwater monitoring associated with the four remediation projects at the Conway storage facilities and for which we will not be indemnified will be approximately $200,000 to $400,000 per year following the completion of remediation work. The benefit of the indemnification will be accounted for as a capital contribution to us by Williams as the costs are incurred. Please read Certain Relationships and Related Transactions Omnibus Agreement.

In connection with our operations at the Conway facilities, we are required by the KDHE regulations to provide assurance of our financial capability to plug and abandon the wells and abandon the brine facilities we operate at Conway. Williams has posted two letters of credit on our behalf in an aggregate amount of $17.5 million to guarantee our plugging and abandonment responsibilities for these facilities. We anticipate providing assurance in the form of letters of credit in future periods until such time as we obtain an investment-grade credit rating.

In connection with the construction of Discovery s pipeline, approximately 73 acres of marshland was traversed. Discovery is required to restore marshland in other areas to offset the damage caused during the initial construction. In Phase I of this project, Discovery created new marshlands to replace about half of the traversed acreage. Phase II, which will complete the project, began during 2005 and will cost approximately $2.0 million.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

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 commodity price risk for natural gas and NGLs. We were also exposed to the risk of interest rate fluctuations on our intercompany balances with Williams prior to the forgiveness of these balances by Williams in conjunction with our IPO.

Commodity Price Risk

Certain of Discovery s processing contracts are exposed to the impact of price fluctuations in the commodity markets, including the correlation between natural gas and NGL prices. In addition, price fluctuations in commodity markets could impact the demand for Discovery s services in the future. Carbonate Trend and our fractionation and storage operations are not directly affected by changing commodity prices except for product imbalances, which are exposed to the impact of price fluctuation in NGL markets. Price fluctuations in commodity markets could also impact the demand for storage and fractionation services in the future. In connection with the IPO, Williams transferred to us a gas purchase contract for the purchase of a portion of our fuel requirements at the Conway fractionator at a market price not to exceed a specified level. This physical contract is intended to mitigate the fuel price risk under one of our fractionation contracts which contains a cap on the per-unit fee that we can charge, at times limiting our ability to pass through the full amount of increases in variable expenses to that customer. We and Discovery do not currently use financial derivatives to manage the risks associated with these price fluctuations.

Interest Rate Risk

Historically, our interest rate exposure was related to our advances from Williams. The table below provides information as of December 31, 2004 about our interest rate risk. We have no interest rate risk as of December 31, 2005.

	December 31, 2004	
	Carrying Value	Fair Value
	($ in thousands)	
Advances from Williams	$ 186,024	$ 186,024

These advances are due on demand. Prior to the closing of our IPO, Williams forgave these advances. The variable interest rate was 7.4% at December 31, 2004.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Williams Partners GP LLC
General Partner of Williams Partners L.P.

We have audited the accompanying consolidated balance sheets of Williams Partners L.P. as of December 31, 2005 and 2004, and the related consolidated statements of operations, partners capital, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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. We were not engaged to perform an audit of the Partnership s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and 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 Williams Partners L.P. at December 31, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As described in Note 7, effective January 1, 2003, Williams Partners L.P. adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, and effective December 31, 2005, adopted Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2005

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WILLIAMS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS

	December 31,			
	2005		2004	
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	6,839	$	
Accounts receivable:				
Trade		1,840		2,150
Other		2,104		1,388
Product imbalance		760		
Gas purchase contract affiliate		5,320		
Prepaid expenses		1,133		749
Total current assets		17,996		4,287
Investment in Discovery Producer Services		150,260		147,281
Property, plant and equipment, net		67,931		67,793
Gas purchase contract noncurrent affiliate		4,754		
Total assets	$	240,941	$	219,361
LIABILITIES AND PARTNERS CAPITAL				
Current liabilities:				
Accounts payable:				
Trade	$	3,906	$	2,480
Affiliate		4,729		1,980
Product imbalance				1,071
Deferred revenue		3,552		3,305
Accrued liabilities		2,373		3,924
Total current liabilities		14,560		12,760
Advances from affiliate				186,024
Environmental remediation liabilities		3,964		3,909
Other noncurrent liabilities		762		
Commitments and contingent liabilities (Note 13)				
Partners capital:				
Predecessor partners equity				16,668
Common unitholders (7,006,146 outstanding at December 31, 2005)		108,526		
Subordinated unitholders (7,000,000 outstanding at December 31, 2005)		108,491		
General partner		4,638		
Total partners capital		221,655		16,668
Total liabilities and partners capital	$	240,941	$	219,361

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2005	2004	2003
	(In thousands)		
Revenues:			
Storage:			
Affiliate	$	$	$ 2,426
Third-party	20,290	15,318	9,223
Fractionation	10,770	9,070	8,221
Gathering	3,063	3,883	5,513
Product sales:			
Affiliate	13,400	506	
Third-party	63	7,947	1,263
Other	4,183	4,252	1,648
Total revenues	51,769	40,976	28,294
Costs and expenses:			
Operating and maintenance expense:			
Affiliate	13,378	9,986	8,789
Third-party	11,733	9,390	5,171
Product cost	11,821	6,635	1,263
Depreciation and accretion	3,619	3,686	3,707
General and administrative expense:			
Affiliate	4,186	2,534	1,738
Third-party	1,137	79	75
Taxes other than income	700	716	640
Other net	(6)	(91)	(133)
Total costs and expenses	46,568	32,935	21,250
Operating income	5,201	8,041	7,044
Equity earnings Discovery Producer Services	8,331	4,495	3,447
Impairment of investment in Discovery Producer Services		(13,484)	
Interest expense:			
Affiliate	(7,461)	(11,980)	(4,176)
Third-party	(777)	(496)	
Interest income	165		
Income (loss) before cumulative effect of change in accounting principle	5,459	(13,424)	6,315
Cumulative effect of change in accounting principle	(628)		(1,099)
Net income (loss)	$ 4,831	$ (13,424)	$ 5,216

Allocation of net income:

Net income	$	4,831
Net loss applicable to the period through August 22, 2005		(103)
Net income applicable to the period August 23 through December 31, 2005		4,934
Allocation of net loss to general partner		(1,273)
Allocation of net income to limited partners	$	6,207
Basic and diluted net income per limited partner unit:		
Income before cumulative effect of change in accounting principle:		
Common units	$	0.49
Subordinated units	$	0.49
Cumulative effect of change in accounting principle:		
Common units	$	(0.05)
Subordinated units	$	(0.05)
Net income:		
Common units	$	0.44
Subordinated units	$	0.44
Weighted average number of units outstanding:		
Common units		7,001,366
Subordinated units		7,000,000

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

	Pre-IPO Owner s Equity	Limited Partners Common	Limited Partners Subordinated	General Partner	Accumulated Other Comprehensive Income (Loss)	Total Partners Capital
		(Dollars in thousands)				
Balance January 1, 2003	$ 24,876	$	$	$	$ (1,962)	$ 22,914
Comprehensive income:						
Net Income 2003	5,216					5,216
Other comprehensive income:						
Net unrealized losses					(116)	(116)
Net reclassification into earnings of derivative instrument losses					2,078	2,078
Total other comprehensive income						1,962
Total comprehensive income						7,178
Balance December 31, 2003	30,092					30,092
Net loss 2004	(13,424)					(13,424)
Balance December 31, 2004	16,668					16,668
Accounts receivable not contributed	(2,640)					(2,640)
Net loss attributable to the period through August 22, 2005	(103)					(103)
	13,925					13,925
Contribution of net assets of predecessor companies (2,000,000 common units; 7,000,000 subordinated units)	(13,925)	10,471	106,427	4,343		107,316
Issuance of units to public (5,000,000 common units)		100,247				100,247
Offering costs		(4,291)				(4,291)
Net income (loss) attributable to the period August 23, 2005 through December 31, 2005		3,104	3,103	(1,273)		4,934
		(1,039)	(1,039)	(42)		(2,120)

Cash distributions ($.1484 per unit)						
Issuance of common units (6,146 common units)		34				34
Contributions pursuant to the Omnibus Agreement				1,610		1,610
Balance December 31, 2005	$	$ 108,526	$ 108,491	$ 4,638	$	$ 221,655

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	**2004**	**2003**
		(In thousands)	
OPERATING ACTIVITIES:			
Net income (loss) before cumulative effect of change in accounting principle	$ 5,459	$ (13,424)	$ 6,315
Adjustments to reconcile to cash provided by operations:			
Depreciation and accretion	3,619	3,686	3,707
Impairment of investment in Discovery Producer Services		13,484	
Amortization of gas purchase contract affiliate	2,033		
Undistributed earnings of Discovery Producer Services	(7,051)	(4,495)	(3,447)
Cash provided (used) by changes in assets and liabilities:			
Accounts receivable	(3,045)	261	(850)
Other current assets	(384)	(362)	(187)
Accounts payable	4,215	2,711	(274)
Accrued liabilities	(737)	(417)	(320)
Deferred revenue	247	775	1,108
Other, including changes in noncurrent assets and liabilities	(2,463)	484	592
Net cash provided by operating activities	1,893	2,703	6,644
INVESTING ACTIVITIES:			
Capital expenditures	(3,688)	(1,534)	(1,167)
Contribution to Discovery Producer Services	(24,400)		(101,643)
Net cash used by investing activities	(28,088)	(1,534)	(102,810)
FINANCING ACTIVITIES:			
Proceeds from sale of common units	100,247		
Payment of offering costs	(4,291)		
Distribution to The Williams Companies, Inc.	(58,756)		
Changes in advances from affiliates net	(3,656)	(1,169)	96,166
Distributions to unitholders	(2,120)		
Contributions per omnibus agreement	1,610		
Net cash provided (used) by financing activities	33,034	(1,169)	96,166
Increase in cash and cash equivalents	6,839		
Cash and cash equivalents at beginning of year			
Cash and cash equivalents at end of year	$ 6,839	$	$

See accompanying notes to consolidated financial statements.

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization

Unless the context clearly indicates otherwise, references in this report to we, our, us or like terms refer to Williams Partners L.P. and its subsidiaries. Unless the context clearly indicates otherwise, references to we, our, and us include the operations of Discovery Producer Services LLC (Discovery), in which we own a 40 percent interest. When we refer to Discovery by name, we are referring exclusively to its businesses and operations.

We are a Delaware limited partnership that was formed in February 2005, to acquire and own (1) a 40 percent interest in Discovery; (2) the Carbonate Trend gathering pipeline off the coast of Alabama; (3) three integrated natural gas liquids (NGL) product storage facilities near Conway, Kansas; and (4) a 50 percent undivided ownership interest in a fractionator near Conway, Kansas. Prior to the closing of our initial public offering (the IPO) in August 2005, the 40 percent interest in Discovery was held by Williams Energy, L.L.C. (Energy) and Williams Discovery Pipeline LLC; the Carbonate Trend gathering pipeline was held in Carbonate Trend Pipeline LLC (CTP), which was owned by Williams Mobile Bay Producers Services, L.L.C.; and the NGL product storage facilities and the interest in the fractionator were owned by Mid-Continent Fractionation and Storage, LLC (MCFS). All of these are wholly owned indirect subsidiaries of The Williams Companies, Inc. (collectively Williams). Williams Partners GP LLC, a Delaware limited liability company, was also formed in February 2005, to serve as our general partner. We also formed Williams Partners Operating LLC, an operating limited liability company (wholly owned by us) through which all our activities are conducted,.

Initial Public Offering and Related Transactions

On August 23, 2005, we completed our IPO of 5,000,000 common units representing limited partner interests in us at a price of $21.50 per unit. The proceeds of $100.2 million, net of the underwriters discount and a structuring fee totaling $7.3 million, were used to:

- distribute $58.8 million to Williams, in part to reimburse Williams for capital expenditures relating to the assets contributed to us and for a gas purchase contract contributed to us;

- provide $24.4 million to make a capital contribution to Discovery to fund an escrow account required in connection with the Tahiti pipeline lateral expansion project;

- provide $12.7 million of additional working capital; and

- pay $4.3 million of expenses associated with the IPO and related formation transactions.

Concurrent with the closing of the IPO, the 40 percent interest in Discovery and all of the interests in CTP and MCFS were contributed to us by Williams subsidiaries in exchange for an aggregate of 2,000,000 common units and 7,000,000 subordinated units. The public, through the underwriters of the offering, contributed $107.5 million ($100.2 million net of the underwriters discount and a structuring fee) to us in exchange for 5,000,000 common units, representing a 35 percent limited partner interest in us. Additionally, at the closing of the IPO, the underwriters fully exercised their option to purchase 750,000 common units from Williams subsidiaries at the IPO price of $21.50 per unit, less the underwriters discount and a structuring fee.

Note 2. Description of Business

We are principally engaged in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. Operations of our businesses are located in the United States and are organized into two reporting segments: (1) Gathering and Processing and (2) NGL Services. Our Gathering and Processing segment includes our equity investment in Discovery and the Carbonate Trend gathering pipeline. Our NGL Services segment includes the Conway fractionation and storage operations.

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gathering and Processing. We own a 40 percent interest in Discovery, which includes a wholly owned subsidiary, Discovery Gas Transmission LLC. Discovery owns (1) a 273-mile natural gas gathering and transportation pipeline system, located primarily off the coast of Louisiana in the Gulf of Mexico, (2) a 600 million cubic feet per day cryogenic natural gas processing plant in Larose, Louisiana, (3) a 32,000 barrels per day (bpd) natural gas liquids fractionator in Paradis, Louisiana and (4) two onshore liquids pipelines, including a 22-mile mixed NGL pipeline connecting the gas processing plant to the fractionator and a 10-mile condensate pipeline connecting the gas processing plant to a third party oil gathering facility. Although Discovery includes fractionation operations, which would normally fall within the NGL Services segment, it is primarily engaged in gathering and processing and is managed as such. Hence, this equity investment is considered part of the Gathering and Processing segment.

Our Carbonate Trend gathering pipeline is an unregulated sour gas gathering pipeline consisting of approximately 34 miles of pipeline off the coast of Alabama.

NGL Services. Our Conway storage facilities include three underground NGL storage facilities in the Conway, Kansas, area with a storage capacity of approximately 20 million barrels. The facilities are connected via a series of pipelines. The storage facilities receive daily shipments of a variety of products, including mixed NGLs and fractionated products. In addition to pipeline connections, one facility offers truck and rail service.

Our Conway fractionation facility is located near McPherson, Kansas, and has a capacity of approximately 107,000 bpd. We own a 50 percent undivided interest in these facilities representing capacity of approximately 53,500 bpd. ConocoPhillips and ONEOK, Inc. are the other owners. Williams operates the facility pursuant to an operating agreement that extends until May 2011. The fractionator separates mixed NGLs into five products: ethane, propane, normal butane, isobutane and natural gasoline. Portions of these products are then transported and stored at our Conway storage facilities.

Note 3. Summary of Significant Accounting Policies

Basis of Presentation. The consolidated financial statements have been prepared based upon accounting principles generally accepted in the United States and include the accounts of the parent and our wholly owned subsidiaries. Intercompany accounts and transactions have been eliminated.

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

Estimates and assumptions which, in the opinion of management, are significant to the underlying amounts included in the financial statements and for which it would be reasonably possible that future events or information could change those estimates include:

- impairment assessments of investments and long-lived assets;
- loss contingencies;
- environmental remediation obligations; and
- asset retirement obligations.

These estimates are discussed further throughout the accompanying notes.

Proportional Accounting for the Conway Fractionator. No separate legal entity exists for the fractionator. We hold a 50 percent undivided interest in the fractionator property, plant and equipment, and we are responsible for our proportional share of the costs and expenses of the fractionator. As operator of the facility, we incur the liabilities of the fractionator (except for certain fuel costs purchased directly by one of the co-

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

owners) and are reimbursed by the co-owners for their proportional share of the total costs and expenses. Each co-owner is responsible for the marketing of their proportional share of the fractionator s capacity. Accordingly, we reflect our proportionate share of the revenues and costs and expenses of the fractionator in the Consolidated Statements of Operations; and we reflect our proportionate share of the fractionator property, plant and equipment in the Consolidated Balance Sheets. Liabilities in the Consolidated Balance Sheets include those incurred on behalf of the co-owners with corresponding receivables from the co-owners. Accounts receivable also includes receivables from our customers for fractionation services.

Cash and Cash Equivalents. Cash and cash equivalents include demand and time deposits, certificates of deposit and other marketable securities with maturities of three months or less when acquired.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. No allowance for doubtful accounts is recognized at the time the revenue which generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been unsuccessful.

Investments. The voting rights under Discovery s limited liability company agreement are such that our 40 percent interest combined with the additional interest held by Williams do not control Discovery. Hence, we account for our investment in Discovery under the equity method. Prior to 2004, the excess of the carrying value of our investment over the amount of underlying equity in net assets of Discovery represented interest capitalized during construction on the funds advanced to Discovery for construction prior to Discovery s receipt of external financing. This excess was being amortized on a straight-line basis over the life of the related assets. In 2004, we recognized an other-than-temporary impairment of our investment. As a result, Discovery s underlying equity exceeds the carrying value of our investment at December 31, 2005.

Property, Plant and Equipment. Property, plant and equipment is recorded at cost. We base the carrying value of these assets on capitalized costs, useful lives and salvage values. Depreciation of property, plant and equipment is provided on the straight-line basis over estimated useful lives. Expenditures for maintenance and repairs are expensed as incurred. Expenditures that enhance the functionality or extend the useful lives of the assets are capitalized. The cost of property, plant and equipment sold or retired and the related accumulated depreciation is removed from the accounts in the period of sale or disposition. Gains and losses on the disposal of property, plant and equipment are recorded in the Consolidated Statements of Operations.

We record an asset and a liability equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in operating income.

Revenue Recognition. The nature of our businesses result in various forms of revenue recognition. Our Gathering and Processing segment recognizes revenue from gathering services when the services have been performed. Our NGL Services segment recognizes (1) fractionation revenues when services have been performed and product has been delivered, (2) storage revenues under prepaid contracted storage capacity evenly over the life of the contract as services are provided and (3) product sales revenue when the product has been delivered.

Gas purchase contract. In connection with the IPO, Williams transferred to us a gas purchase contract for the purchase of a portion of our fuel requirements at the Conway fractionator at a market price not to exceed a specified level. The gas purchase contract is for the purchase of 80,000 MMBtu per month and

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

terminates on December 31, 2007. The initial value of this contract is being amortized to expense over the contract life.

Product Imbalances. In the course of providing fractionation and storage services to our customers, we realize product gains and losses that are reflected as product imbalance receivables or payables on the Consolidated Balance Sheets. These imbalances are valued based on the market price of the products when the imbalance is identified and are evaluated for the impact of a change in market prices at the balance sheet date. Certain of these product gains and losses arise due to the product blending process at the fractionator. Others are realized when storage caverns are emptied. Storage caverns are emptied periodically to determine whether any product gains or losses have occurred, and as these caverns are emptied, it is possible that the resulting product gains or losses could have a material impact to the results of operations for the period during which the cavern drain is performed.

Impairment of Long-Lived Assets and Investments. We evaluate our long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate the carrying value of such assets may not be recoverable. The impairment evaluation of tangible long-lived assets is measured pursuant to the guidelines of Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. When an indicator of impairment has occurred, we compare our management s estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether the carrying value of the assets is recoverable. We apply a probability weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes. If the carrying value is not recoverable, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our management s judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment.

Judgments and assumptions are inherent in our management s estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset s fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

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

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 contamination caused by past operations that do not contribute to current or future revenue generation are expensed. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account our prior remediation experience. Environmental contingencies are recorded independently of any potential claim for recovery.

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Capitalized Interest. We capitalize interest on major projects during construction to the extent we incur interest expense. Historically, Williams provided the financing for capital expenditures; hence, the rates used to calculate the interest were based on Williams average interest rate on debt during the applicable period in time.

Earnings Per Unit. In accordance with the Emerging Issues Task Force (EITF) Issue 03-6, we use the two-class method to calculate basic and diluted earnings per unit whereby net income, adjusted for items specifically allocated to our general partner, is allocated on a pro-rata basis between unitholders and our general partner. Basic and diluted earnings per unit are based on the average number of common and subordinated units outstanding. Basic and diluted earnings per unit are equivalent as there are no dilutive securities outstanding.

Recent Accounting Standards. In December 2004, the Financial Accounting Standards Board (FASB) issued revised SFAS No. 123, Share-Based Payment. The Statement requires that compensation costs for all share-based awards to employees be recognized in the financial statements at fair value. The Statement, as issued by the FASB, was to be effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. However, in April 2005, the Securities and Exchange Commission (SEC) adopted a new rule that delayed the effective date for revised SFAS No. 123 to the beginning of the next fiscal year that begins after June 15, 2005. We intend to adopt the revised Statement as of January 1, 2006. Payroll costs directly charged to us by Williams and general and administrative costs allocated to us by Williams (see Note 5) will include such compensation costs beginning January 1, 2006. Our and Williams adoption of this Statement will not have a material impact on our Consolidated Financial Statements.

In November 2004, the FASB issued SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4, which will be applied prospectively for inventory costs incurred in fiscal years beginning after June 15, 2005. The Statement amends Accounting Research Bulletin (ARB) No. 43, Chapter 4, Inventory Pricing, to clarify that abnormal amounts of certain costs should be recognized as current period charges and that the allocation of overhead costs should be based on the normal capacity of the production facility. The impact of this Statement on our Consolidated Financial Statements will not be material.

In December 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, which is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005, and will be applied prospectively. The Statement amends APB Opinion No. 29, Accounting for Nonmonetary Transactions. The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but includes certain exceptions to that principle. SFAS No. 153 amends APB Opinion 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.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3, which is effective prospectively for reporting a change in accounting principle for fiscal years beginning after December 15, 2005. The Statement changes the reporting of a change in accounting principle to require retrospective application to prior periods financial statements, except for explicit transition provisions provided for in any existing accounting pronouncements, including those in the transition phase when SFAS No. 154 becomes effective.

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4. Allocation of Net Income and Distributions

The allocation of net income between our general partner and limited partners for the period August 23, 2005 through December 31, 2005 is as follows (in thousands):

Allocation of net income to general partner:		
Net income for the period August 23, 2005 through December 31, 2005	$	4,934
Direct charges to general partner:		
Reimbursable general and administrative costs		1,400
Income before direct charges to general partner		6,334
General partner s share of net income		2.0%
General partner s allocated share of net income before direct charges		127
Direct charges to general partner		(1,400)
Net loss allocated to general partner	$	(1,273)
Net income for the period August 23, 2005 through December 31, 2005	$	4,934
Net loss allocated to general partner		(1,273)
Net income allocated to limited partners	$	6,207

The reimbursable general and administrative costs represent the general and administrative costs charged against our income that are required to be reimbursed to us by our general partner under the terms of the Omnibus Agreement.

On November 14, 2005, we paid a cash distribution of $0.1484 per unit on our outstanding common and subordinated units to unitholders of record at the close of business on November 7, 2005. The distribution represents the $0.35 per unit minimum quarterly distribution pro-rated for the 39-day period following the IPO closing date (August 23, 2005 through September 30, 2005). The total distribution, including distributions paid to our general partner on its equivalent units, was $2.1 million.

On February 14, 2006, we paid a cash distribution of $0.35 per unit on our outstanding common and subordinated units to unitholders of record on February 7, 2006. The total distribution, including distributions paid to our general partner on its equivalent units, was $5.0 million.

Note 5. Related Party Transactions

The employees of our operated assets and all of our general and administrative employees are employees of Williams. Williams directly charges us for the payroll costs associated with the operations employees and certain general and administrative employees. Williams carries the obligations for most employee-related benefits in its financial statements, including the liabilities related to the employee retirement and medical plans and paid time off. Certain of these costs are charged back to the other Conway fractionator co-owners. Our share of those costs are charged to us through affiliate billings and reflected in Operating and maintenance expense Affiliate in the accompanying Consolidated Statements of Operations.

Williams charges its affiliates, including us and its Midstream segment, of which we are a part, for certain corporate administrative expenses that are directly identifiable or allocable to the affiliates. Direct costs charged from Williams represent the direct costs of services provided by Williams on our behalf. Prior to the IPO, a portion of the charges allocated to the Midstream segment were then reallocated to us. These allocated corporate administrative expenses are based on a three-factor formula, which considered revenues; property, plant and equipment; and payroll.

Certain of these costs are charged back to the other Conway fractionator co-owners. Our share of these costs is reflected in General and administrative expense Affiliate in the

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

accompanying Consolidated Statements of Operations. In management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to us of our costs of doing business incurred by Williams. Under the Omnibus Agreement, Williams gives us a quarterly credit for general and administrative expenses. These amounts are reflected as a capital contribution from our general partner. The annual amounts of the credits are as follows: $3.9 million in 2005 ($1.4 million pro-rated for the portion of the year from August 23 to December 31), $3.2 million in 2006, $2.4 million in 2007, $1.6 million in 2008 and $0.8 million in 2009.

At December 31, 2005, we have a contribution receivable from our general partner of $.3 million, which is netted against Partners capital on the Consolidated Balance Sheets, for amounts reimbursable to us under the Omnibus Agreement.

We purchase fuel for the Conway fractionator, including fuel on behalf of the co-owners, from Williams Power Company (Power), a wholly owned subsidiary of Williams. These purchases are made at market rates at the time of purchase. In connection with the IPO, Williams transferred to us a gas purchase contract for the purchase of a portion of our fuel requirements at the Conway fractionator at a market price not to exceed a specified level. The amortization of this contract is reflected in Operating and maintenance expense Affiliate in the accompanying Consolidated Statements of Operations. The carrying value of this contract is reflected as Gas purchase contract affiliate and Gas purchase contract noncurrent affiliate on the Consolidated Balance Sheets.

During a portion of 2003, we provided propane storage, fractionation, transportation and terminalling services to subsidiaries of Williams that have subsequently been sold. In December 2004, we began selling surplus propane and other NGLs to Power, which takes title to the product and resells it, for its own account, to end users. Revenues associated with these activities are reflected as Affiliate revenues on the Consolidated Statements of Operations. Correspondingly, we purchase ethane and other NGLs from Power to replenish deficit product positions. The transactions conducted between us and Power are transacted at current market prices for the products.

A summary of the general and administrative expenses directly charged and allocated to us, fuel purchases from Power and NGL purchases from Power for the periods stated is as follows:

	2005	2004	2003
		(In thousands)	
General and administrative expenses, including amounts subsequently charged to co-owners:			
Allocated	$ 3,494	$ 2,078	$ 1,392
Directly charged	992	456	346
Operating and maintenance expenses, including amounts subsequently charged to co-owners:			
Fuel purchases, including amortization of gas contract	24,478	17,053	12,843
Salaries and benefits	3,514	3,473	2,105
NGL purchases	15,657	1,271	

The per-unit gathering fee associated with two of our Carbonate Trend gathering contracts was negotiated on a bundled basis that includes transportation along a segment of a pipeline system owned by Transcontinental Gas Pipe Line Company (Transco), a wholly owned subsidiary of Williams. The fees we realize are dependent upon whether our customer elects to utilize this Transco capacity. When they make this election, our gathering fee is determined by subtracting the Transco tariff from the total negotiated fee. The rate associated with the capacity agreement is based on a Federal Energy Regulatory Commission tariff that is subject to change. Accordingly, if the Transco rate increases, our net gathering fees for these two contracts

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

may be reduced. The customers with these bundled contracts must make an annual election to receive this capacity. For 2005 and 2006, only one of our customers has elected to utilize this capacity.

We historically participated in Williams cash management program; thus, we carried no cash balance on our Consolidated Balance Sheet at December 31, 2004. Effective with the IPO, we began maintaining our own bank accounts but continue to utilize Williams personnel to manage our cash and investments. As of December 31, 2004, our net Advances from affiliate consisted of an unsecured promissory note agreement with Williams for both advances to and from Williams. The advances were due on demand; however, Williams did not historically require repayment. Therefore, Advances from affiliate at December 31, 2004 were classified as noncurrent. Prior to the closing of the IPO, Williams forgave the advances due to them at the date the net assets were transferred to us. Accordingly, the advances balance was transferred to Partners capital at that date.

Affiliate interest expense includes interest on the advances with Williams calculated using Williams weighted average cost of debt applied to the outstanding balance of the advances with Williams and commitment fees on the working capital credit facility (see Note 11). The interest rate on the advances with Williams was 7.373 percent at December 31, 2004.

Note 6. Investment in Discovery Producer Services

Our 40 percent investment in Discovery is accounted for using the equity method of accounting. At December 31, 2005, Williams owned an additional 20 percent ownership interest in Discovery through Energy. Although we and Williams hold a 60 percent interest in Discovery on a combined basis, the voting provisions of Discovery s limited liability company agreement give the other member of Discovery significant participatory rights such that we and Williams do not control Discovery.

Of the total ownership interest owned by Williams prior to the transfer of 40 percent to us, a portion was acquired by Williams in April 2005 resulting in a revised basis used for the calculation of the 40 percent interest transferred to us in connection with the IPO. As a result, the carrying value of our 40 percent interest in Discovery and Partners capital decreased $11.0 million during the second quarter of 2005.

On August 22, 2005, Discovery made a distribution of approximately $43.8 million to Williams and the other member of Discovery at that date. This distribution was associated with Discovery s operations prior to the IPO; hence, we did not receive any portion of this distribution. The distribution resulted in a revised basis used for the calculation of the 40 percent interest transferred to us in connection with the IPO. As a result, the carrying value of our 40 percent interest in Discovery and Partners capital decreased $17.5 million during the third quarter of 2005.

In September 2005, we made a $24.4 million capital contribution to Discovery for a substantial portion of our share of the estimated future capital expenditures for the Tahiti pipeline lateral expansion project.

Williams is the operator of Discovery. Discovery reimburses Williams for actual payroll and employee benefit costs incurred on its behalf. In addition, Discovery pays Williams a monthly operations and management fee to cover the cost of accounting services, computer systems and management services provided to it. Discovery also has an agreement with Williams pursuant to which Williams markets the NGLs and excess natural gas to which Discovery takes title.

During 2004, we performed an impairment review of this investment because of Williams planned purchase of an additional interest in Discovery at an amount below its carrying value. As a result, we recorded a $13.5 million impairment of our investment in Discovery based on a probability-weighted estimation of fair value of our investment. In December 2003, each of the owners made an additional investment in Discovery, which was subsequently used by Discovery to repay maturing debt. Our proportionate share of this additional investment was approximately $101.6 million.

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Due to the significance of Discovery s equity earnings to our results of operations, the summarized financial position and results of operations for 100 percent of Discovery are presented below (in thousands).

	December 31,	
	2005	2004
Current assets	$ 70,525	$ 67,534
Non-current restricted cash	44,559	
Property, plant and equipment	344,743	356,385
Current liabilities	(45,070)	(31,572)
Non-current liabilities	(1,121)	(702)
Members capital	$ 413,636	$ 391,645

	Years Ended December 31,		
	2005	2004	2003
Revenues	$ 122,745	$ 99,876	$ 103,178
Costs and expenses	102,597	88,756	84,519
Interest expense			9,611
Interest income	(1,685)	(550)	
Foreign exchange loss	1,005		
Income before cumulative effect of change in accounting principle	$ 20,828	$ 11,670	$ 9,048
Net income	$ 20,652	$ 11,670	$ 8,781

Note 7. Property, Plant and Equipment

Property, plant and equipment, at cost, is as follows:

	December 31,		Estimated Depreciable Lives
	2005	2004	
	(In thousands)		
Land and right of way	$ 2,373	$ 2,373	
Fractionation plant and equipment	16,646	16,555	30 years
Storage plant and equipment	65,892	63,632	30 years
Pipeline plant and equipment	23,684	23,684	20-30 years
Construction work in progress	1,886	566	
Other	1,492	1,490	5-45 years

Total property, plant and equipment		111,973		108,300
Accumulated depreciation		44,042		40,507
Net property, plant and equipment	$	67,931	$	67,793

We adopted SFAS No. 143, Accounting for Asset Retirement Obligations on January 1, 2003. As a result, we recorded a liability of $993,000 representing the present value of expected future asset retirement obligations at January 1, 2003, and a decrease to earnings of $992,000 reflected as a cumulative effect of a change in accounting principle. An additional $107,000 reduction of earnings is reflected as a cumulative

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effect of a change in accounting principle for our 40 percent interest in Discovery s cumulative effect of a change in accounting principle related to the adoption of SFAS No. 143.

Effective December 31, 2005, we adopted FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability s fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. As required by the new standard, we reassessed the estimated remaining life of all our assets with a conditional ARO. We recorded additional liabilities totaling $573,000 equal to the present value of expected future asset retirement obligations at December 31, 2005. The liabilities are slightly offset by a $16,000 increase in property, plant and equipment, net of accumulated depreciation, recorded as if the provisions of the Interpretation had been in effect at the date the obligation was incurred. The net $557,000 reduction to earnings is reflected as a cumulative effect of a change in accounting principle for the year ended 2005. An additional $70,000 reduction of earnings is reflected as a cumulative effect of a change in accounting principle for our 40 percent interest in Discovery s cumulative effect of a change in accounting principle related to the adoption of FIN No. 47. If the Interpretation had been in effect at the beginning of 2003, the impact to our income from continuing operations and net income would have been immaterial.

The obligations relate to underground storage caverns and the associated brine ponds. At the end of the useful life of each respective asset, we are legally obligated to properly abandon the storage caverns, empty the brine ponds and restore the surface, and remove any related surface equipment.

A rollforward of our asset retirement obligation for 2005 and 2004 is presented below.

	2005	2004
	(In thousands)	
Balance, January 1	$ 760	$ 801
Liabilities incurred during the period	91	79
Liabilities settled during the period	(204)	(166)
Accretion expense	1	83
Estimate revisions	(460)	
FIN No. 47 revisions	574	
Gain on settlements		(37)
Balance, December 31	$ 762	$ 760

Note 8. Accrued Liabilities

Accrued liabilities are as follows:

	December 31,	
	2005	2004
	(In thousands)	
Environmental remediation current portion	$ 1,424	$ 1,633
Customer volume deficiency payment		749
Asset retirement obligation current portion		760
Employee costs affiliate	387	317
Taxes other than income	375	359

Other	187	106
	$ 2,373	$ 3,924

WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9. Long-Term Incentive Plan

In November 2005, our general partner adopted the Williams Partners GP LLC Long-Term Incentive Plan (the Plan) for employees, consultants and directors of our general partner and its affiliates who perform services for us. The Plan permits the grant of awards covering an aggregate of 700,000 common units. These awards may be in the form of options, restricted units, phantom units or unit appreciation rights. The compensation committee of our general partner s board of directors administers the Plan.

During November and December 2005, our general partner granted 6,146 restricted units pursuant to the Plan to members of our general partner s board of directors who are not officers or employees of our general partner or its affiliates. These restricted units vest six months from grant date. We recognized compensation expense of $34 thousand associated with these awards in 2005.

Note 10. Major Customers, Concentrations of Credit Risk and Financial Instruments

Major customers

In 2005, four customers, Williams Power Company (an affiliate company), SemStream, L.P., Enterprise and BP Products North America, Inc. (BP) accounted for approximately 25.9 percent, 17.1 percent, 14.1 percent and 13.5 percent, respectively, of our total revenues. In 2004, three customers, SemStream, L.P., BP and Enterprise accounted for approximately 20.6 percent, 16.1 percent and 16.0 percent, respectively, of our total revenues. In 2003, four customers, BP, Enterprise, Chevron and Williams Power Company, accounted for approximately 24.6 percent, 15.9 percent, 14.7 percent and 11.6 percent, respectively, of our total revenues. SemStream, L.P., BP, Enterprise and Williams Power Company are customers of the NGL Services segment. Chevron is a customer of the Gathering and Processing segment.

Our Carbonate Trend gathering pipeline has only two customers. The loss of either of these customers, unless replaced, would have a significant impact on the Gathering and Processing segment.

Concentrations of credit risk

Our cash equivalents consist of high-quality securities placed with various major financial institutions with credit ratings at or above AA by Standard & Poor s or Aa by Moody s Investor s Service.

The following table summarizes the concentration of accounts receivable by service and segment.

	December 31,	
	2005	2004
	(In thousands)	
Gathering and Processing:		
Natural gas gathering	$ 525	$ 441
NGL Services:		
Fractionation services	532	468
Amounts due from fractionator partners	1,834	1,381
Storage	793	1,241
Other	260	7
	$ 3,944	$ 3,538

Our fractionation and storage customers include crude refiners; propane wholesalers and retailers; gas producers; natural gas plant, fractionator and storage operators; and NGL traders and pipeline operators. Our two Carbonate Trend natural gas gathering customers are oil and gas producers. While sales to our customers are unsecured, we routinely evaluate their financial condition and creditworthiness.

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments.

Cash and cash equivalents. The carrying amounts reported in the balance sheets approximate fair value due to the short-term maturity of these instruments.

Advances from affiliates. At December 31, 2004, our net Advances from affiliate consisted of an unsecured promissory note agreement with Williams for both advances to and from Williams. The carrying amounts reported in the Consolidated Balance Sheet approximate fair value as this instrument had an interest rate approximating market.

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 6,839	$ 6,839		
Advances from affiliates			$ 186,024	$ 186,024

Note 11. Credit Facilities and Leasing Activities

Credit Facilities

On May 20, 2005, Williams amended its $1.275 billion revolving credit facility (Williams facility), which is available for borrowings and letters of credit, to allow us to borrow up to $75 million under the Williams facility. Borrowings under the Williams facility mature on May 3, 2007. Our $75 million borrowing limit under the Williams facility is available for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Williams and its other subsidiaries. At December 31, 2005, letters of credit totaling $378 million had been issued on behalf of Williams by the participating institutions under the Williams facility and no revolving credit loans were outstanding.

Interest on any borrowings under the Williams facility is calculated based on our choice of two methods: (i) a fluctuating rate equal to the facilitating bank s base rate plus an applicable margin or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. We are also required to pay or reimburse Williams for a commitment fee based on the unused portion of its $75 million borrowing limit under the Williams facility, currently 0.325 percent annually. The applicable margin, currently 1.75 percent, and the commitment fee are based on Williams senior unsecured long-term debt rating. Under the Williams facility, Williams and certain of its subsidiaries, other than us, are required to comply with certain financial and other covenants. Significant financial covenants under the Williams facility to which Williams is subject include the following:

- ratio of debt to net worth no greater than (i) 70 percent through December 31, 2005, and (ii) 65 percent for the remaining term of the agreement;

- ratio of debt to net worth no greater than 55 percent for Northwest Pipeline Corporation, a wholly-owned subsidiary of Williams, and Transco; and

- ratio of EBITDA to interest, on a rolling four quarter basis, no less than (i) 2.0 for any period after March 31, 2005 through December 31, 2005, and (ii) 2.5 for the remaining term of the agreement.

In August 2005, we entered into a $20 million revolving credit facility (the credit facility) with Williams as the lender. The credit facility is available exclusively to fund working capital requirements. Borrowings under the credit facility mature on May 3, 2007 and bear interest at the same rate as for borrowings under the Williams facility described above. We pay a commitment fee to Williams on the unused portion of the credit facility of 0.30 percent annually. We are required to reduce all borrowings under the

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

credit facility to zero for a period of at least 15 consecutive days once each 12-month period prior to the maturity date of the credit facility. No amounts have been drawn on this facility.

Leasing Activities

We lease automobiles for use in our NGL Services segment. We account for these leases as operating leases. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2005 are as follows (in thousands):

2006	$ 30
2007	29
2008	27
2009	10
2010	
	$ 96

Total rent expense was $119,000, $110,000 and $116,000 for 2005, 2004 and 2003, respectively.

Note 12. Partners Capital

Of the 7,006,146 common units outstanding at December 31, 2005, 5,756,146 are held by the public, with the remaining 1,250,000 held by our affiliates. All of the 7,000,000 subordinated units are held by our affiliates.

Upon expiration of the subordination period, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. The subordination period will end on the first day of any quarter beginning after June 30, 2008 or when we meet certain financial tests provided for in our partnership agreement.

Significant information regarding rights of the limited partners include the following:

Right to receive distributions of available cash within 45 days after the end of each quarter.

No limited partner shall have any management power over our business and affairs; the general partner shall conduct, direct and manage our activities.

The general partner may be removed if such removal is approved by the unitholders holding at least $66^{2}/3$ percent of the outstanding units voting as a single class, including units held by our general partner and its affiliates.

Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

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

Quarterly Distribution Target Amount (per unit)	Unitholders	General Partner
Minimum quarterly distribution of $0.35	98%	2%
Up to $0.4025	98	2
Above $0.4025 up to $0.4375	85	15
Above $0.4375 up to $0.5250	75	25
Above $0.5250	50	50

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In the event of a liquidation, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and our general partner, in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Other Comprehensive Income

The main component of our accumulated other comprehensive loss is our share of Discovery s accumulated other comprehensive loss which is related to a cash flow hedge of interest rate risk held by Discovery in 2003.

Note 13. Commitments and Contingencies

Environmental Matters. We are a participant in certain environmental remediation activities associated with soil and groundwater contamination at our Conway storage facilities. These activities relate to four projects that are in various remediation stages including assessment studies, cleanups and/or remedial operations and monitoring. We continue to coordinate with the Kansas Department of Health and Environment (KDHE) to develop screening, sampling, cleanup and monitoring programs. The costs of such activities will depend upon the program scope ultimately agreed to by the KDHE and are expected to be paid over the next two to nine years.

In 2004, we purchased an insurance policy that covers up to $5 million of remediation costs until an active remediation system is in place or April 30, 2008, whichever is earlier, excluding operation and maintenance costs and ongoing monitoring costs, for these projects to the extent such costs exceed a $4.2 million deductible. The policy also covers costs incurred as a result of third party claims associated with then existing but unknown contamination related to the storage facilities. The aggregate limit under the policy for all claims is $25 million. In addition, under an omnibus agreement with Williams entered into at the closing of the IPO, Williams has agreed to indemnify us for the $4.2 million deductible (less amounts expended prior to the closing of the IPO) of remediation expenditures not covered by the insurance policy, excluding costs of project management and soil and groundwater monitoring. There is a $14 million cap on the total amount of indemnity coverage under the omnibus agreement, which will be reduced by actual recoveries under the environmental insurance policy. There is also a three-year time limitation from the IPO closing date, August 23, 2005. The benefit of this indemnification will be accounted for as a capital contribution to us by Williams as the costs are reimbursed. We estimate that the approximate cost of this project management and soil and groundwater monitoring associated with the four remediation projects at the Conway storage facilities and for which we will not be indemnified will be approximately $200,000 to $400,000 per year following the completion of the remediation work.

At December 31, 2005, we had accrued liabilities totaling $5.4 million for these costs. It is reasonably possible that we will incur losses in excess of our accrual for these matters. However, a reasonable estimate of such amounts cannot be determined at this time because actual costs incurred will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by KDHE and other governmental authorities and other factors.

Other. We are not currently a party to any legal proceedings but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our future financial position.

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 14. 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 industry knowledge, technology and marketing strategies. The accounting policies of the segments are the same as those described in Note 3, Summary of Significant Accounting Policies. Long-lived assets are comprised of property, plant and equipment.

	Gathering & Processing	NGL Services	Total
		(In thousands)	
2005			
Segment revenues	$ 3,515	$ 48,254	$ 51,769
Operating and maintenance expense	714	24,397	25,111
Product cost		11,821	11,821
Depreciation and accretion	1,200	2,419	3,619
Direct general and administrative expenses	2	1,068	1,070
Other, net		694	694
Segment operating income	1,599	7,855	9,454
Equity earnings	8,331		8,331
Segment profit	$ 9,930	$ 7,855	$ 17,785
Reconciliation to the Statement of Operations:			
Segment operating income			$ 9,454
General and administrative expenses:			
Allocated affiliate			(3,194)
Third-party direct			(1,059)
Combined operating income			$ 5,201
Other financial information:			
Segment assets	$ 171,009	$ 64,579	$ 235,588
Other assets and eliminations			5,353
Total assets			$ 240,941
Equity method investments	$ 150,260	$	$ 150,260
Additions to long-lived assets		3,688	3,688

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WILLIAMS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Gathering & Processing	NGL Services	Total
		(In thousands)	
2004			
Segment revenues	$ 4,833	$ 36,143	$ 40,976
Operating and maintenance expense	572	18,804	19,376
Product cost		6,635	6,635
Depreciation and accretion	1,200	2,486	3,686
Direct general and administrative expenses		535	535
Other, net		625	625
Segment operating income	3,061	7,058	10,119
Equity earnings	4,495		4,495
Impairment of investment	(13,484)		(13,484)
Segment profit (loss)	$ (5,928)	$ 7,058	$ 1,130
Reconciliation to the Statement of Operations:			
Segment operating income			$ 10,119
Allocated general and administrative expenses			(2,078)
Combined operating income			$ 8,041
Other financial information:			
Total assets	$ 166,985	$ 52,376	$ 219,361
Equity method investments	147,281		147,281
Additions to long-lived assets		1,622	1,622
2003			
Segment revenues	$ 5,513	$ 22,781	$ 28,294
Operating and maintenance expense	379	13,581	13,960
Product cost		1,263	1,263
Depreciation and accretion	1,200	2,507	3,707
Direct general and administrative expenses		421	421
Other, net		507	507
Segment operating income	3,934	4,502	8,436
Equity earnings	3,447		3,447
Segment profit	$ 7,381	$ 4,502	$ 11,883
Reconciliation to the Statement of Operations:			
Segment operating income			$ 8,436
Allocated general and administrative expenses			(1,392)
Combined operating income			$ 7,044

Other financial information:			
Total assets	$ 177,769	$ 52,381	$ 230,150
Equity method investments	156,269		156,269
Additions to long-lived assets		1,176	1,176

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WILLIAMS PARTNERS L.P.
QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows (thousands, except per-unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2005				
Revenues	$ 11,369	$ 12,176	$ 12,176	$ 16,048
Costs and operating expenses	10,266	8,036	13,175	15,091
Income (loss) before cumulative effect of change in accounting principle	311	1,849	(2,871)	6,170
Net income (loss)	311	1,849	(2,871)	5,542
Basic and diluted net income (loss) per limited partner unit:				
Income (loss) before cumulative effect of change in accounting principle:				
Common units	NA	NA	$ (0.02)	$ 0.51
Subordinated units	NA	NA	$ (0.02)	$ 0.51
Cumulative effect of change in accounting principle:				
Common units	NA	NA	$	$ (0.05)
Subordinated units	NA	NA	$	$ (0.05)
Net income (loss):				
Common units	NA	NA	$ (0.02)	$ 0.46
Subordinated units	NA	NA	$ (0.02)	$ 0.46

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2004				
Revenues	$ 7,953	$ 9,043	$ 10,457	$ 13,523
Costs and operating expenses	5,256	8,289	8,956	10,434
Income (loss) before cumulative effect of change in accounting principle	1,569	(1,125)	(1,684)	(12,184)
Net income (loss)	1,569	(1,125)	(1,684)	(12,184)

Net income for fourth-quarter 2005 includes our 40 percent share of Discovery s favorable adjustment of $10.7 million related to amounts previously deferred for net system gains from 2002 through 2004 that were reversed following the acceptance in 2005 of a filing with the FERC.

Net loss for third-quarter 2005 includes a $3.4 million unfavorable product imbalance adjustments included in NGL services.

Net loss for fourth-quarter 2004 includes a $13.5 million impairment of our investment in Discovery Producer Services (see Note 6).

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Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15(d) (e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our general partner s management, including our general partner s chief executive officer and chief financial officer. Based upon that evaluation, our general partner s chief executive officer and chief financial officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Our management, including our general partner s chief executive officer and chief financial officer, does not expect that our Disclosure Controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. 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 Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and the Internal Controls will be modified as systems change and conditions warrant.

Management concludes that its current controls are effective at a reasonable assurance level. In addition, there has been no material change in our Internal Controls that occurred during the registrant s fourth fiscal quarter.

Item 9B. ***Other Information***

There have been no events that occurred in the fourth quarter of 2005 that would need to be reported on Form 8-K that have not been previously reported.

PART III

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

Our general partner manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation.

We are managed and operated by the directors and officers of our general partner. All of our operational personnel are employees of an affiliate of our general partner.

All of the senior officers of our general partner are also senior officers of Williams and spend a sufficient amount of time overseeing the management, operations, corporate development and future acquisition initiatives of our business. Alan Armstrong, the chief operating officer of our general partner, is the principal executive responsible for the oversight of our affairs. Our non-executive directors will devote as much time as is necessary to prepare for and attend board of directors and committee meetings.

The following table shows information for the directors and executive officers of our general partner as of February 28, 2006.

Name	Age	Position with Williams Partners GP LLC
Steven J. Malcolm	57	Chairman of the Board and Chief Executive Officer
Donald R. Chappel	54	Chief Financial Officer and Director
Alan S. Armstrong	43	Chief Operating Officer and Director
James J. Bender	48	General Counsel
Thomas C. Knudson	59	Director and Member of Audit, Conflicts and Compensation Committees
Bill Z. Parker	58	Director and Member of Audit, Conflicts and Compensation Committees
Alice M. Peterson	53	Director and Member of Audit, Conflicts and Compensation Committees
Phillip D. Wright	50	Director

The directors of our general partner are elected for one-year terms and hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of the directors or executive officers of our general partner. All of our operational personnel are employees of an affiliate of our general partner.

Steven J. Malcolm has served as the chairman of the board of directors and chief executive officer of our general partner since February 2005. Mr. Malcolm has served as president of Williams since September 2001, chief executive of Williams since January 2002 and chairman of the board of directors of Williams since May 2002. Mr. Malcolm has served as a member of the board of directors of the BOK Financial Corporation since 2002. From May 2001 to September 2001, he served as executive vice president of Williams. From December 1998 to May 2001, he served as president and chief executive officer of Williams Energy Services, LLC. From November 1994 to December 1998, Mr. Malcolm served as the senior vice president and general manager of Williams Field Services Company. Mr. Malcolm served as chief executive officer and chairman of the board of directors of the general partner of Williams Energy Partners L.P. from the initial public offering in February 2001 of Williams Energy Partners L.P. (now known as Magellan Midstream Partners, L.P.) to the sale of Williams interests therein in June 2003. Mr. Malcolm has been named as a defendant in numerous shareholder class action suits that have been filed against Williams. These class actions include issues related to the spin-off of WilTel Communications, a previously-owned subsidiary of Williams, Williams Power Company, and public offerings in January 2001, August 2001 and January 2002, known as the FELINE PACS offering. Additionally, four class action complaints were filed under the Employee Retirement Income Security Act of 1974 (ERISA) against Williams, certain committee members and certain members of Williams board of directors, including Mr. Malcolm, by participants in Williams Investment Plus Plan. Final court approval of the ERISA litigation and dismissal with prejudice occurred in November 2005.

Donald R. Chappel has served as the chief financial officer and a director of our general partner since February 2005. Mr. Chappel has served as senior vice president and chief financial officer of Williams since April 2003. Prior to joining Williams, Mr. Chappel, from 2000 to April 2003, founded and served as chief executive officer of a development business in Chicago, Illinois. From 1987 though February 2000, Mr. Chappel served in various financial, administrative and operational leadership positions for Waste Management, Inc., including twice serving as chief financial officer, during 1997 and 1998 and most recently during 1999 through February 2000.

Alan S. Armstrong has served as the chief operating officer and a director of our general partner since February 2005. Mr. Armstrong has served as a senior vice president of Williams since February 2002

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responsible for heading Williams midstream business unit. From 1999 to February 2002, Mr. Armstrong was vice president, gathering and processing in Williams midstream business unit and from 1998 to 1999 was vice president, commercial development in Williams midstream business unit. From 1997 to 1998, Mr. Armstrong was vice president of retail energy in Williams energy services business unit. Prior to this, Mr. Armstrong served in various operations, engineering and commercial leadership roles within Williams.

James J. Bender has served as the general counsel of our general partner since February 2005. Mr. Bender has served as senior vice president and general counsel of Williams since December 2002. From June 2000 until joining Williams, Mr. Bender was senior vice president and general counsel with NRG Energy, Inc. Mr. Bender was vice president, general counsel and secretary of NRG Energy from June 1997 to June 2000. NRG Energy filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.

Thomas C. Knudson has served as a director of our general partner since November 2005. Mr. Knudson has served as a member of the board of directors of Bristow Group Inc. (formerly Offshore Logistics, Inc.), a leading provider of helicopter transportation services to the oil and gas industry, since January 2004. Mr. Knudson has also served as a director of NATCO Group Inc., a leading provider of wellhead process equipment, systems and services used in the production of oil and gas, since April 2005. From 2000 to 2003, he was a senior vice president of ConocoPhillips.

Bill Z. Parker has served as a director of our general partner since August 2005. Mr. Parker has served as a director for Latigo Petroleum, Inc., a privately-held independent oil and gas production company, since January 2003. From April 2000 to November 2002, he served as executive vice president of Phillips Petroleum Company s worldwide upstream operations. Mr. Parker was executive vice president of Phillips Petroleum Company s worldwide downstream operations from September 1999 to April 2000.

Alice M. Peterson has served as a director of our general partner since September 2005. Ms. Peterson is the president of Syrus Global, a provider of ethics, compliance and reputation management solutions. Ms. Peterson has served as a director for RIM Finance, LLC, a wholly owned subsidiary of Research In Motion, Ltd., the maker of the BlackBerry™ handheld device, since 2000. Ms. Peterson served as a director of TBC Corporation, a marketer of private branded replacement tires, from July 2005 to November 2005, when it was acquired by Sumitomo Corporation of America. From 1998 to August 2004, she served as a director of Fleming Companies. From December 2000 to December 2001, she served as president and general manager of RIM Finance, LLC. From April 2000 to September 2000, Ms. Peterson served as the chief executive officer of Guidance Resources.com, a start-up business focused on providing online behavioral health and concierge services to employer groups and other associations. From 1998 to 2000, she served as vice president of Sears Online and from 1993 to 1998, as vice president and treasurer of Sears, Roebuck and Co. Following the bankruptcy of Fleming Companies in 2003, Ms. Peterson was named as a defendant, along with each other member of the company s board of directors, in a securities class action. The case was settled and all claims against Ms. Peterson were released and dismissed after the court s approval of the settlement which became a final judgment in December 2005. Ms. Peterson has also been named as a defendant, along each other member of the board of directors of Fleming Companies, in connection with a claim by trade creditors of Dunigan Fuels (a subsidiary of the former Fleming Companies) for conspiracy to breach fiduciary duties.

Phillip D. Wright has served as a director of our general partner since February 2005. Mr. Wright has served as senior vice president of Williams gas pipeline operations since January 2005. From October 2002 to January 2005, Mr. Wright served as chief restructuring officer of Williams. From September 2001 to October 2002, Mr. Wright served as president and chief executive officer of Williams Energy Services. From 1996 to September 2001, he was senior vice president, enterprise development and planning for Williams energy services group. From 1989 to 1996, Mr. Wright served in various capacities for Williams. Mr. Wright served as president, chief operating officer and director of the general partner of Williams Energy Partners L.P. from the initial public offering in February 2001 of Williams Energy Partners L.P. (now known as Magellan Midstream Partners, L.P.) to the sale of Williams interests therein in June 2003. Mr. Wright has been named as a defendant in four class action complaints filed under ERISA against Williams, certain members of the benefits and investment committees and certain members of the Williams board of directors, by participants

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in Williams Investment Plus Plan. Final court approval of the ERISA litigation and dismissal with prejudice occurred in November 2005.

Governance Matters

In August 2005 our general partner adopted governance guidelines. The governance guidelines address, among other areas, director independence standards, policies on meeting attendance and preparation, executive sessions of non-management directors and communications with non-management directors.

Director Independence

Because we are a limited partnership, our general partner s board of directors is not required to be composed of a majority of directors who meet the criteria for independence required by the New York Stock Exchange and is not required to maintain nominating/corporate governance and compensation committees composed entirely of independent directors.

Our general partner s board of directors annually reviews the independence of directors and affirmatively makes a determination that each director expected to be independent has no material relationship with our general partner (either directly or indirectly or as a partner, shareholder or officer of an organization that has a relationship with our general partner). In order to make this determination, our general partner s board of directors broadly considers all relevant facts and circumstances and applies categorical standards from our governance guidelines. Under those categorical standards, a director will not be considered to be independent if:

the director, or an immediate family member of the director, has received during any twelve-month period within the last three years more than $100,000 per year in direct compensation from our general partner, us, and any parent or subsidiary in a consolidated group with such entities (collectively, the Partnership Group), other than board and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service). Neither compensation received by a director for former service as an interim chairman or chief executive officer or other executive officer nor compensation received by an immediate family member for service as an employee of the Partnership Group will be considered in determining independence under this standard.

the director is a current employee, or has an immediate family member who is a current executive officer, of another company that has made payments to, or received payments from, the Partnership Group for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million, or two percent of the other company s consolidated gross annual revenues. Contributions to tax exempt organizations are not considered payments for purposes of this standard.

the director is, or has been within the last three years, an employee of the Partnership Group, or an immediate family member is, or has been within the last three years, an executive officer, of the Partnership Group. Employment as an interim chairman or chief executive officer or other executive officer will not disqualify a director from being considered independent following that employment.

(i) the director or an immediate family member is a current partner of a present or former internal or external auditor for the Partnership Group, (ii) the director is a current employee of such a firm, (iii) the director has an immediate family member who is a current employee of such a firm and participates in such firm s audit, assurance or tax compliance (but not tax planning) practice or (iv) the director or an immediately family member was within the last three years (but is no longer) a partner or employee of such a firm and personally worked on an audit for the Partnership Group within that time.

if the director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the Partnership Group s present executive officers at the same time serves or served on that company s compensation committee.

if the board of directors determines that a discretionary contribution made by any member of the Partnership Group to a non-profit organization with which a director, or a director s spouse, has a relationship, impacts the director s independence.

Our general partners board of directors has affirmatively determined that each of Ms. Peterson and Messrs. Knudson and Parker is an independent director under the current listing standards of the New York Stock Exchange and our categorical director independence standards. In doing so, the board of directors determined that each of these individuals met the bright line independence standards of the New York Stock Exchange. In addition, the board of directors considered relationships with our general partner, either directly or indirectly. The purpose of this review was to determine whether any such relationships or transactions were inconsistent with a determination that the director is independent. The board of directors considered the fact that Mr. Knudson serves as a director for NATCO Group Inc., which provides goods or services for affiliates of Williams. The board of directors also considered the fact that Ms. Peterson is a director of an affiliate of Research in Motion Corp. and was a director of TBC Corporation, which provides goods or services to affiliates of Williams. The board of directors noted that, since Ms. Peterson and Mr. Knudson do not serve as an executive officer and are not a significant stockholder of these companies, these relationships are not material and affirmatively determined that all of the directors mentioned above are independent.

Meeting Attendance and Preparation

Members of the board of directors are expected to attend at least 75 percent of regular board meetings and meetings of the committees on which they serve, either in person or telephonically. In addition, directors are expected to be prepared for each meeting of the board by reviewing written materials distributed in advance.

Executive Sessions of Non-Management Directors

The general partners non-management board members periodically meet outside the presence of our general partners executive officers. The chairman of the audit committee serves as the presiding director for executive sessions of non-management board members. The current chairman of the audit committee and the presiding director is Mr. Bill Z. Parker.

Communications with Directors

Interested parties wishing to communicate with the our non-management directors may contact our general partners corporate secretary or the presiding director. The contact information is published on the investor relations page of our website at *http://www.williamslp.com.*

The current contact information is as follows:

Williams Partners L.P.
One Williams Center, Suite 4700
Tulsa, Oklahoma 74172
Attn: Corporate Secretary

Williams Partners L.P.
One Williams Center, Suite 4700
Tulsa, Oklahoma 74172
Attn: Presiding Director

Email: *brian.shore@williams.com*

Board Committees

The board of directors of our general partner has a separately-designated standing audit committee established in accordance with section 3(a)(58)(A) of the Securities Exchange Act of 1934, a conflicts committee and a compensation committee. The following is a description of each of the committees and committee membership as of February 28, 2006.

Board Committee Membership

	Audit Committee	Conflicts Committee	Compensation Committee
Thomas C. Knudson	ü	ü	
Bill Z. Parker		ü	ü
Alice M. Peterson	ü		ü

ü = committee member
= chairperson

Audit Committee

Our general partner s board of directors has determined that all members of the audit committee meet the heightened independence requirements of the New York Stock Exchange for audit committee members and that all members are financially literate as defined by the rules of the New York Stock Exchange. The board of directors has further determined that Ms. Alice M. Peterson is an audit committee financial expert as defined by the rules of the SEC. Ms. Peterson s biographical information is set forth above under the caption Directors and Executive Officers of the Registrant. The audit committee is governed by a written charter adopted by the board of directors. For further information about the audit committee, please read the Report of the Audit Committee below and Principal Accountant Fees and Services.

Compensation Committee

Our general partner s board of directors has established a compensation committee to administer the Williams Partners GP LLC Long-Term Incentive Plan for employees, consultants and directors of our general partner and employees and consultants of its affiliates who perform services for our general partner and its affiliates. The long-term incentive plan consists of four components: restricted units, phantom units, unit options and unit appreciation rights. The plan permits the grant of awards covering an aggregate of 700,000 units. To date, the only grants made pursuant to the plan are restricted units related to director compensation. For more information about the long-term incentive plan, please read Compensation of Directors and Long-Term Incentive Plan under Executive Compensation and Securities Authorized Under Equity Compensation Plans under Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters. The compensation committee is governed by a written charter adopted by the board of directors.

Conflicts Committee

The conflicts committee of our general partner s board of directors reviews specific matters that the board believes may involve conflicts of interest. The conflicts committee determines if resolution of the conflict is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, and must meet the independence and experience requirements established by the New York Stock Exchange and the Sarbanes-Oxley Act of 2002 and other federal securities laws. Any matters approved by the conflicts committee will be conclusively deemed fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe to us or our unitholders.

Internet Access to Governance Documents

Our general partner s code of business conduct and ethics, governance guidelines and the charters for the audit and compensation committees are available on our Internet website at *http://www.williamslp.com* under the Investor Relations caption. We will provide, free of charge, a copy of our code of business conduct and ethics or any of our other governance documents listed above upon written request to our general partner s secretary at Williams Partners L.P., One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our general partner s officers and directors, and persons who own more than 10 percent of a registered class of our equity securities to file with the SEC and the New York Stock Exchange reports of ownership of Company securities and changes in reported ownership. Officers and directors of our general partner and greater than 10 percent common unitholders are required to by SEC rules to furnish to us copies of all Section 16(a) reports that they file. Based solely on a review of reports furnished to our general partner, or written representations from reporting persons that all reportable transactions were reported, we believe that during the fiscal year ended December 31, 2005 our general partner s officers, directors and greater than 10 percent common unitholders filed all reports they were required to file under Section 16(a).

Code of Business Conduct and Ethics

Our general partner has adopted a code of business conduct and ethics for directors, officers and employees. We intend to disclose any amendments to or waivers of the code of business conduct and ethics on behalf of our general partner s chief executive officer, chief financial officer, controller and persons performing similar functions on our Internet website at *http://www.williamslp.com* under the Investor Relations caption, promptly following the date of any such amendment or waiver.

REPORT OF THE AUDIT COMMITTEE

The audit committee oversees our financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee operates under a written charter approved by the board. The charter, among other things, provides that the audit committee has full authority to appoint, retain and oversee the independent auditor. In this context, the audit committee:

reviewed and discussed the audited financial statements in this annual report on Form 10-K with management, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements;

reviewed with Ernst & Young LLP, the independent auditors, who are responsible for expressing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, their judgments as to the quality and acceptability of Williams Partners L.P. s accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards;

received the written disclosures and the letter required by standard No. 1 of the independence standards board (independence discussions with audit committees) provided to the audit committee by Ernst & Young LLP;

discussed with Ernst & Young LLP its independence from management and Williams Partners L.P. and considered the compatibility of the provision of nonaudit services by the independent auditors with the auditors independence;

discussed with Ernst & Young LLP the matters required to be discussed by statement on auditing standards No. 61 (communications with audit committees);

discussed with Williams Partners L.P. s internal auditors and Ernst & Young LLP the overall scope and plans for their respective audits. The audit committee meets with the internal auditors and Ernst & Young LLP, with and without management present, to discuss the results of their examinations, their

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evaluations of Williams Partners L.P. s internal controls and the overall quality of Williams Partners L.P. s financial reporting;

based on the foregoing reviews and discussions, recommended to the board of directors that the audited financial statements be included in the annual report on Form 10-K for the year ended December 31, 2005, for filing with the SEC; and

approved the selection and appointment of Ernst & Young LLP to serve as Williams Partners L.P. s independent auditors for 2006.

This report has been furnished by the members of the audit committee of the board of directors:

Bill Z. Parker chairman
Alice M. Peterson
Thomas C. Knudson

February 24, 2006

The report of the audit committee in this report shall not be deemed incorporated by reference into any other filing by Williams Partners L.P. under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under such acts.

Item 11. ***Executive Compensation***

We and our general partner were formed in February 2005. We have no employees. We are managed by the officers of our general partner. We reimburse Williams for direct and indirect general and administrative expenses incurred on our behalf. For the fiscal year ended December 31, 2005, Williams allocated approximately $22,341 of salary and bonus expense to us (and our predecessor for the portion of the year prior to our formation) for Steven J. Malcolm, the chairman of the board and chief executive officer of our general partner, and approximately $27,659 for all other expenses related to his compensation. For the fiscal year ended December 31, 2004, Williams allocated approximately $19,846 of salary and bonus expense to our predecessor for Mr. Malcolm and approximately $14,873 for all other expenses related to his compensation. Allocated expenses related to Mr. Malcolm s compensation other than salary and bonus included Williams deferred stock awards, matching contributions made under a Williams 401(k) plan, and premiums for life insurance. We also allocated a portion of Williams expenses related to perquisites which did not exceed $50,000 or 10 percent of Mr. Malcolm s salary and bonus from Williams. The foregoing amounts exclude expenses allocated by Williams to Discovery. Total compensation received by Mr. Malcolm, who is also the chairman, president and chief executive officer of Williams, will be set forth in the proxy statement for Williams 2006 annual meeting of shareholders which will be available upon its filing on the SEC s website at *http://www.sec.gov* and on Williams website at *http://www.williams.com* under the heading Investors SEC Filings. No other executive officer of our general partner received salary and bonus compensation allocable to us or our predecessor in excess of $100,000 and no awards were granted to our general partner s executive officers under the Williams Partners GP LLC Long-Term Incentive Plan in 2004 or 2005.

Employment Agreements

The executive officers of our general partner are also executive officers of Williams. These executive officers do not have employment agreements in their capacity as officers of our general partner.

Compensation of Directors

Members of the board of directors of our general partner who are also officers or employees of our affiliates do not receive additional compensation for serving on the board of directors. Subject to the proration provisions of the policy, members of the board of directors who are not officers or employees of our affiliates (each a Non-Employee Director) each receive an annual compensation package consisting of the following: (a) $50,000 cash; (b) restricted units representing limited partnership interests in us valued at $25,000; and

(c) $5,000 cash each for service on the conflicts and audit committees of the board. In addition, each Non-Employee Director receives a one-time grant of restricted units valued at $25,000. Restricted units are granted under the Williams Partners GP LLC Long-Term Incentive Plan and vest 180 days after the date of grant. Cash distributions will be paid on the restricted units granted to the Non-Employee Directors. Each Non-Employee Director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Each director will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law. We also reimburse Non-Employee directors for the costs of education programs relevant to their duties as board members.

Long-Term Incentive Plan

In connection with our IPO, our general partner adopted the Williams Partners GP LLC Long-Term Incentive Plan for employees, consultants and directors of our general partner and employees and consultants of its affiliates who perform services for our general partner or its affiliates. To date, the only grants under the plan have been grants of restricted units to Non-Employee Directors. The long-term incentive plan consists of four components: restricted units, phantom units, unit options and unit appreciation rights. The long-term incentive plan currently permits the grant of awards covering an aggregate of 700,000 units. The plan is administered by the compensation committee of the board of directors of our general partner.

Our general partner s board of directors, or its compensation committee, in its discretion may terminate, suspend or discontinue the long-term incentive plan at any time with respect to any award that has not yet been granted. Our general partner s board of directors, or its compensation committee, also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Restricted Units and Phantom Units

A restricted unit is a common unit subject to forfeiture prior to the vesting of the award. A phantom unit will be a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. The compensation committee may determine to make grants under the plan of restricted units and phantom units to employees, consultants and directors containing such terms as the compensation committee shall determine. The compensation committee determines the period over which restricted units and phantom units granted to employees, consultants and directors will vest. The committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units and phantom units will vest upon a change of control of Williams Partners L.P., our general partner or Williams, unless provided otherwise by the compensation committee.

If a grantee s employment, service relationship or membership on the board of directors terminates for any reason, the grantee s restricted units and phantom units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. Common units to be delivered in connection with the grant of restricted units or upon the vesting of phantom units may be common units acquired by our general partner on the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner is entitled to reimbursement by us for the cost incurred in acquiring common units. Thus, the cost of the restricted units and delivery of common units upon the vesting of phantom units will be borne by us. If we issue new common units in connection with the grant of restricted units or upon vesting of the phantom units, the total number of common units outstanding will increase. The compensation committee, in its discretion, may grant tandem distribution rights with respect to restricted units and tandem distribution equivalent rights with respect to phantom units.

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Unit Options and Unit Appreciation Rights

The long-term incentive plan permits the grant of options covering common units and the grant of unit appreciation rights. A unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a unit on the exercise date over the exercise price established for the unit appreciation right. Such excess may be paid in common units, cash or a combination thereof, as determined by the compensation committee in its discretion. The compensation committee may make grants of unit options and unit appreciation rights under the plan to employees, consultants and directors containing such terms as the committee shall determine. Unit options and unit appreciation rights may not have an exercise price that is less than the fair market value of the common units on the date of grant. In general, unit options and unit appreciation rights granted will become exercisable over a period determined by the compensation committee. In addition, the unit options and unit appreciation rights will become exercisable upon a change in control of Williams Partners L.P., our general partner or Williams, unless provided otherwise by the committee. The compensation committee, in its discretion may grant tandem distribution equivalent rights with respect to unit options and unit appreciation rights.

Upon exercise of a unit option (or a unit appreciation right settled in common units), our general partner will acquire common units on the open market or directly from us or any other person or use common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring these common units and the proceeds received from a participant at the time of exercise. Thus, the cost of the unit options (or a unit appreciation right settled in common units) will be borne by us. If we issue new common units upon exercise of the unit options (or a unit appreciation right settled in common units), the total number of common units outstanding will increase, and our general partner will pay us the proceeds it receives from an optionee upon exercise of a unit option. The availability of unit options and unit appreciation rights is intended to furnish additional compensation to employees, consultants and directors and to align their economic interests with those of common unitholders.

Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of Williams Partners L.P. Our general partner and its affiliates are reimbursed for expenses incurred on our behalf, including the compensation of employees of an affiliate of our general partner that perform services on our behalf. These expenses include all expenses necessary or appropriate to the conduct of the business of, and allocable to, Williams Partners L.P. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to Williams Partners L.P. There is no cap on the amount that may be paid or reimbursed to our general partner for compensation or expenses incurred on our behalf, except that pursuant to the omnibus agreement, Williams will provide a partial credit for general and administrative expenses that we incur for a period of five years following our IPO of common units in August 2005. Please read Certain Relationships and Related Transactions Omnibus Agreement.

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

The following table sets forth the beneficial ownership of units of Williams Partners L.P. that, as of February 28, 2006, are owned by:

each person known by us to be a beneficial owner of more than five percent of the units;

each of the directors of our general partner;

each of the named executive officers of our general partner; and

all directors and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Percentage of total units beneficially ownership is based on 14,006,146 units outstanding. Unless otherwise noted below, the address for the beneficial owners listed below is One Williams Center, Tulsa, Oklahoma 74172-0172.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Beneficially Owned	Percentage of Total Units Beneficially Owned
The Williams Companies, Inc.(a)	1,250,000	17.9%	7,000,000	100.0%	58.9%
Williams Energy Services, LLC	821,761	11.7	4,601,861	65.7	38.7
Williams Energy, L.L.C.	447,308	6.4	2,504,925	35.8	23.0
Williams Discovery Pipeline LLC	215,980	3.1	1,209,486	17.3	10.2
Williams Partners Holdings LLC	428,239	6.1	2,398,139	34.2	20.2
MAPCO Inc.(a)	447,308	6.4	2,504,925	35.8	23.0
Fiduciary Asset Management, L.L.C.(b)	632,465	9.0			4.5
Alan S. Armstrong	10,000	*			*
James J. Bender	2,000	*			*
Donald R. Chappel	10,000	*			*
Steven J. Malcolm(c)	25,100	*			*
Bill Z. Parker(d)	7,326	*			*
Alice M. Peterson(d)	2,326	*			*
Thomas C. Knudson(d)	1,494	*			*
Phillip D. Wright	2,000	*			*
All directors and executive officers as a group (eight persons)	60,246	*			*

* Less than one percent.

(a) As noted in the Schedule 13D filed with the SEC on September 2, 2005, The Williams Companies, Inc. is the ultimate parent company of Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Discovery Pipeline LLC and Williams Partners Holdings LLC and may, therefore, be deemed to beneficially own the units held by Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Discovery Pipeline LLC and Williams Partners Holdings LLC. The Williams Companies, Inc. s common stock is listed on the New York Stock

Exchange under the symbol WMB. The Williams Companies, Inc. files information with or furnishes information to, the Securities and Exchange Commission pursuant to the information requirements of the Securities Exchange Act of 1934 (the Act). Williams Energy Services, LLC is the record owner of 158,473 common units and 887,450 subordinated units and, as the sole stockholder of MAPCO Inc. and the sole member of Williams Discovery Pipeline LLC, may, pursuant to Rule 13d-3, be deemed to beneficially own the units beneficially owned by MAPCO Inc. and Williams Discovery Pipeline LLC. MAPCO Inc., as the sole member of Williams Energy, L.L.C., may, pursuant to Rule 13d-3, be deemed to beneficially own the units held by Williams Energy, L.L.C.

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(b) Based solely on the Schedule 13G filed with the SEC on February 16, 2006, Fiduciary Asset Management, L.L.C. (FAMCO), an investment sub-adviser to certain closed-end investment companies registered under the Investment Company Act of 1940 as well as to private individuals, may be deemed the beneficial owner of 632,465 common units. FAMCO by virtue of investment advisory agreements with these clients has all investment and voting power over securities owned of record by these clients. However, despite their delegation of investment and voting power to FAMCO, these clients may be deemed to be the beneficial owners under Rule 13d-3 of the Act of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with FAMCO. Thus, FAMCO reported that it shares voting power and dispositive power over the securities owned of record by these clients. FAMCO may be deemed the beneficial owner of the securities covered by this statement under Rule 13-3 of the Act. None of the securities listed below are owned of record by FAMCO and FAMCO disclaims any beneficial interest in the securities. The filing further indicates that except for Fiduciary/ Claymore MLP Opportunity Fund, a Delaware statutory Trust, which may be deemed to beneficially own 426,400 common units, the interest of any one person does not exceed five percent of our outstanding common units. The Schedule 13G notes that each of FAMCO and Fiduciary/ Claymore have shared voting and investment power with respect to their common units. The address of FAMCO is 8112 Maryland Avenue, Suite 400, St. Louis, Missouri, 63105.

(c) Represents units beneficially owned by Mr. Malcolm that are held by the Steven J. Malcolm Revocable Trust.

(d) Includes unvested restricted units granted pursuant to the Williams Partners GP LLC Long-Term Incentive Plan which may be voted by the grantees as follows: Mr. Knudson, 1,494; Mr. Parker, 2,326; and Ms. Peterson, 2,326.

The following table sets forth, as of February 28, 2006, the number of shares of common stock of Williams owned by each of the executive officers and directors of our general partner and all directors and executive officers of our general partner as a group.

Name of Beneficial Owner	Shares of Common Stock Owned Directly or Indirectly(a)	Shares Underlying Options Exercisable Within 60 Days(b)	Total	Percent of Class
Alan S. Armstrong	88,975	13,333	102,308	*
James J. Bender	126,334	13,333	139,667	*
Donald R. Chappel	223,731	118,333	342,064	*
Steven J. Malcolm	670,210	75,000	745,210	*
Bill Z. Parker				
Alice M. Peterson				
Thomas C. Knudson				
Phillip D. Wright	172,631	13,333	185,964	*
All directors and executive officers as a group (eight persons)	1,281,881	233,332	1,515,213	*

* Less than one percent.

(a)

Includes shares held under the terms of incentive and investment plans as follows: Mr. Armstrong, 14 shares in The Williams Companies Investment Plus Plan, 68,660 deferred shares and 20,301 beneficially owned shares; Mr. Bender, 3,000 shares owned by children, 68,600 deferred shares and 54,674 beneficially owned shares; Mr. Chappel, 141,608 deferred shares of which 50,000 vest on April 16, 2006 and 82,123 beneficially owned shares; Mr. Malcolm, 44,623 shares in The Williams Companies Investment Plus Plan, 374,758 deferred shares and 250,829 beneficially owned shares; and Mr. Wright, 14,742 shares in The Williams Investment Plus Plan, 68,660 deferred shares and 89,229 beneficially owned shares.

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(b) The shares indicated represent stock options granted under Williams current or previous stock option plans, which are currently exercisable or which will become exercisable within 60 days of February 28, 2006. Shares subject to options cannot be voted.

Securities Authorized for Issuance Under Equity Compensation Plans(1)

The following table provides information concerning common units that may be issued under the Williams Partners GP LLC Long-Term Incentive Plan. For more information about this plan, which did not require approval by our limited partners, please read Note 9 of our Notes to Consolidated Financial Statements and Executive Compensation Long-Term Incentive Plan.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders	6,146		693,854
Total	6,146(1)		693,854(2)

(1) Represents unvested restricted units granted pursuant to the Williams Partners GP LLC Long-Term Incentive Plan. No value is shown in column (b) of the table because the restricted units do not have an exercise price. To date, the only grants under the plan have been grants of restricted units.

(2) Please read Executive Compensation Long-Term Incentive Plan for a description of the material features of the plan, including the awards that may be granted under the plan.

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

Our general partner and its affiliates own 1,250,000 common units and 7,000,000 subordinated units representing a 59 percent limited partner interest in us. In addition, our general partner owns a two percent general partner interest in us.

In addition to the related transactions and relationships discussed below, information about such transactions and relationships is included in Note 5 of our Notes to Consolidated Financial Statements and is incorporated herein by reference in its entirety.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our general partner and its affiliates in connection with the ongoing operation and liquidation of Williams Partners L.P. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Operational Stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98 percent to unitholders, including our general partner and its affiliates, as holders of an aggregate of 1,250,000 common units, all of the subordinated units and the remaining two percent to our general partner.

	In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner will be entitled to increasing percentages of the distributions, up to 50 percent of the distributions above the highest target level. We refer to the rights to increasing distribution as incentive distribution rights. For further information about distributions, please read Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.
Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for the management of our partnership. Our general partner and its affiliates are reimbursed, however, for all direct and indirect expenses incurred on our behalf. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
	Liquidation Stage
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Agreements Governing the IPO Transactions

We, our general partner, our operating company and other parties entered into agreements to effect the transactions related to our IPO of common units in August 2005, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of this offering. These agreements were not be the result of arm s-length negotiations, and they, or any of the transactions that they provided may not have been effected on terms at least as favorable to the parties to these agreements as they could have been obtained from unaffiliated third parties. From the proceeds of the IPO, we paid approximately $4.3 million of expenses associated with the IPO and the related formation transactions.

Omnibus Agreement

Upon the closing of the IPO, we entered into an omnibus agreement with Williams and its affiliates that governs our relationship with them regarding the following matters:

- reimbursement of certain general and administrative expenses;
- indemnification for certain environmental liabilities, tax liabilities and right-of-way defects;
- reimbursement for certain expenditures; and
- a license for the use of certain software and intellectual property.

General and Administrative Expenses

Williams will provide us with a five-year partial credit for general and administrative, or G&A, expenses incurred on our behalf. For 2005, the amount of this credit was $3.9 million on an annualized basis but was pro rated from the closing of our initial public offering in August 2005 through the end of the year. In 2006, the

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amount of the G&A credit will be $3.2 million, and the amount of the credit will decrease by $800,000 for each subsequent year. As a result, after 2009, we will no longer receive any credit and will be required to reimburse Williams for all of the general and administrative expenses incurred on our behalf.

Indemnification for Environmental and Related Liabilities

Williams agreed to indemnify us after the closing of our IPO against certain environmental and related liabilities arising out of or associated with the operation of the assets before the closing date of the IPO. These liabilities include both known and unknown environmental and related liabilities, including:

- remediation costs associated with the KDHE Consent Orders and certain fugitive NGLs associated with our Conway storage facilities;
- the costs associated with the installation of wellhead control equipment and well meters at our Conway storage facility;
- KDHE-related cavern compliance at our Conway storage facility; and
- the costs relating to the restoration of the overburden along our Carbonate Trend pipeline in connection with erosion caused by Hurricane Ivan in September 2004.

Williams will not be required to indemnify us for any project management or monitoring costs. This indemnification obligation will terminate three years after the closing of the IPO, except in the case of the remediation costs associated with the KDHE Consent Orders which will survive for an unlimited period of time. There is an aggregate cap of $14.0 million on the amount of indemnity coverage, including any amounts recoverable under our insurance policy covering those remediation costs and unknown claims at Conway. For further information about the indemnity obligation, please read Environmental under Management s Discussion and Analysis of Financial Condition and Results of Operations. In addition, we are not entitled to indemnification until the aggregate amounts of claims exceed $250,000. Liabilities resulting from a change of law after the closing of our IPO are excluded from the environmental indemnity by Williams for the unknown environmental liabilities.

Williams will also indemnify us for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to us in connection with the IPO are located and failure to obtain certain consents and permits necessary to conduct our business that arise within three years after the closing of the IPO; and
- certain income tax liabilities attributable to the operation of the assets contributed to us in connection with the IPO prior to the time they were contributed.

Reimbursement for Certain Expenditures Attributable to Discovery

We expect the cost of the Tahiti pipeline lateral expansion project will be approximately $69.5 million, of which our 40 percent share will be approximately $27.8 million. Williams will reimburse us for the excess (up to $3.4 million) of our 40 percent share of the total cost of the Tahiti pipeline lateral expansion project above the amount of the required escrow deposit ($24.4 million) attributable to our 40 percent interest in Discovery. Williams will reimburse us for these capital expenditures upon the earlier to occur of a capital call from Discovery or Discovery actually incurring the expenditure.

Intellectual Property License

Williams and its affiliates granted a license to us for the use of certain marks, including our logo, for as long as Williams controls our general partner, at no charge.

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Amendments

The omnibus agreement may not be amended without the prior approval of the conflicts committee if the proposed amendment will, in the reasonable discretion of our general partner, adversely affect holders of our common units.

Competition

Williams is not restricted under the omnibus agreement from competing with us. Williams may acquire, construct or dispose of additional midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Credit Facilities

Working Capital Facility

At the closing of the IPO, we entered into a $20 million revolving credit facility with Williams as the lender. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility will mature on May 3, 2007 and bear interest at the same rate as would be available for borrowings under the Williams revolving credit facility described in please read Management s Discussion and Analysis of Financial Condition Financial Condition and Liquidity Sources of Liquidity Credit Facility.

We are required to reduce all borrowings under our working capital credit facility to zero for a period of at least 15 consecutive days once each 12-month period prior to the maturity date of the facility.

Williams Revolving Credit Facility

In addition we also have the ability to borrow up to $75 million under the Williams revolving credit facility. For further information, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Financial Condition and Liquidity Sources of Liquidity Credit Facilities and Risk Factors Risks Inherent in Our Business Williams revolving credit facility and Williams public indentures contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future will be affected by Williams credit ratings.

Discovery Limited Liability Company Agreement

We, an affiliate of Williams and Duke Energy Field Services have entered into an amended and restated limited liability company agreement for Discovery Producer Services LLC. This agreement governs the ownership and management of Discovery and provides for quarterly distributions of available cash to the members. The amount of any such distributions are determined by majority approval of Discovery s management committee, which consists of representatives from each of the three owners. In addition, to the extent Discovery requires working capital in excess of applicable reserves, the Williams affiliate that is a Discovery member (Williams Energy, L.L.C.) must make capital advances to Discovery up to the amount of Discovery s two most recent prior quarterly distributions of available cash, but Discovery must repay these advances before it makes any future distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an area of interest.

Discovery Operating and Maintenance Agreements

Discovery is party to three operating and maintenance agreements with Williams: one relating to Discovery Producer Services LLC, one relating to Discovery Gas Transmission LLC and another relating to the Paradis Fractionation Facility and the Larose Gas Processing Plant. Under these agreements, Discovery is required to reimburse Williams for direct payroll and employee benefit costs incurred on Discovery s behalf. Most costs for materials, services and other charges are third-party charges and are invoiced directly to Discovery. Discovery is required to pay Williams a monthly operation and management fee to cover the cost of accounting services, computer systems and management services provided to Discovery under each of these agreements. Discovery also pays Williams a project management fee to cover the cost of managing capital projects. This fee is determined on a project by project basis.

Gas Purchase Contract

Upon the closing of our IPO, an affiliate of Williams transferred to us a contract for the purchase of a sufficient quantity of natural gas from a wholly owned subsidiary of Williams at a price not to exceed a specified price to satisfy our fuel requirements under this fractionation contract. The fair value of this gas purchase contract was an equity contribution to us by Williams. This gas purchase contract will terminate on December 31, 2007.

Natural Gas and NGL Marketing Contracts

A subsidiary of Williams markets substantially all of the NGLs and excess natural gas to which Discovery and our Conway fractionation and storage facility take title. Discovery and our Conway fractionation and storage facility conduct the sales of the NGLs and excess natural gas to which they take title pursuant to a base contract for sale and purchase of natural gas and a natural gas liquids master purchase, sale and exchange agreement. These agreements contain the general terms and conditions governing the transactions such as apportionment of taxes, timing and manner of payment, choice of law and confidentiality. Historically, the sales of natural gas and NGLs to which Discovery and our Conway fractionation and storage facility take title have been conducted at market prices with a subsidiary of Williams as the counter party. Additionally, Discovery and our Conway fractionation and storage facility may purchase natural gas to meet their fuel and other requirements and our Conway storage facility may purchase NGLs as needed to maintain inventory balances.

Summary of Transactions with Williams

In connection with the closing of our IPO:

- we contributed 2,000,000 common units, 7,000,000 subordinated units, a two percent general partner interest and incentive distribution rights to affiliates of Williams in exchange for the interests in our operating subsidiaries and Discovery;

- we distributed $58.8 million to affiliates of Williams to reimburse Williams for certain capital expenditures incurred prior to our formation and for the contribution by an affiliate of Williams to one of our operating subsidiaries of a gas purchase contract that provides for the purchase of a sufficient quantity of natural gas from a wholly owned subsidiary of Williams at a price not to exceed a specified price to satisfy our fuel requirements under a fractionation contract;

- we provided $24.4 million to make a capital contribution to Discovery to fund an escrow account in connection with the Tahiti pipeline lateral expansion project; and

- Williams forgave $186.0 million in intercompany advances to us.

For the year ended December 31, 2005:

- we incurred $17.6 million from Williams for direct and indirect expenses incurred on our behalf pursuant to the partnership agreement;

- we distributed $1.3 million to affiliates of Williams as quarterly distributions on their common units, subordinated units and 2 percent general partner interest;

- we received from Williams $1.4 million of general and administrative credits pursuant to the omnibus agreement;

- Williams indemnified us $0.5 million, primarily for KDHE-required compliance costs, pursuant to the omnibus agreement;

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Discovery reimbursed Williams $3.4 million for direct payroll and employee benefit costs pursuant to the operating and maintenance agreements;

Discovery paid Williams $2.2 million for operation and management fees pursuant to the operating and maintenance agreements;

we purchased a gross amount of $22.4 million of natural gas for the Conway fractionator from an affiliate of Williams;

we purchased $15.7 million of NGLs from a subsidiary of Williams based on market pricing;

we sold $13.4 million to a subsidiary of Williams that markets substantially all of the NGLs and excess natural gas to which our Conway fractionation and storage facility takes title; and

Discovery sold $70.8 million to a subsidiary of Williams that markets substantially all of the NGLs and excess natural gas to which Discovery takes title.

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

We and our general partner we formed in February 2005 and our IPO occurred in August 2005. Fees for professional services provided by our independent auditors, Ernst & Young LLP, for the last fiscal year in each of the following categories are:

	2005
	(Thousands)
Audit Fees	$ 1,624
Audit-Related Fees	
Tax Fees	
All Other Fees	
	$ 1,624

We did not rely on the *de minimus exception* provided for by the SEC s rules for any fee approvals.

Fees for audit services in 2005 include fees associated with the annual audit, the reviews of our quarterly reports on Form 10-Q, and services provided in connection with other filings with the SEC. The audit fees included in the table above include $1.2 million for services rendered in connection with our IPO.

On an ongoing basis, our management presents specific projects and categories of service to our general partner s audit committee for which advance approval is requested. The audit committee reviews those requests and advises management if the audit committee approves the engagement of Ernst & Young LLP. On a periodic basis, the management of the general partner reports to the audit committee regarding the actual spending for such projects and services compared to the approved amounts. The audit committee may also delegate the ability to pre-approve audit and permitted non-audit services, excluding services related to our internal control over financial reporting, to any two committee members, provided that any such pre-approvals are reported at a subsequent audit committee meeting. The audit committee s pre-approval policy with respect to audit and non-audit services is provided as an exhibit to this report.

PART IV

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

(a) *1 and 2. Williams Partners L.P. financials*

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 (b). The exhibits listed below are filed as part of this annual report:*

Exhibit Number	Description
*Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (attached as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on May 2, 2005).
*Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (attached as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on May 2, 2005).
*Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (attached as Exhibit 3.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (attached as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
* Exhibit 10.1	Fractionation Agreement dated July 18, 1997, by and between MAPCO Natural Gas Liquids Inc. and Amoco Oil Company (attached as Exhibit 10.6 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005).
*Exhibit 10.2	Omnibus Agreement among Williams Partners L.P., Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Partners Holdings LLC, Williams Discovery Pipeline LLC, Williams Partners GP LLC, Williams Partners Operating LLC and (for purposes of Articles V and VI thereof only) The Williams Companies, Inc. (attached as Exhibit 10.1

	to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*#Exhibit 10.3	Williams Partners GP LLC Long-Term Incentive Plan (attached as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*Exhibit 10.4	Contribution, Conveyance and Assumption Agreement, dated August 23, 2005, by and among Williams Partners L.P., Williams Energy, L.L.C., Williams Partners GP LLC, Williams Partners Operating LLC, Williams Energy Services, LLC, Williams Discovery Pipeline LLC, Williams Partners Holdings LLC and Williams Natural Gas Liquids, Inc. (attached as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K filed with the SEC on August 26, 2005).
*Exhibit 10.5	Working Capital Loan Agreement, dated August 23, 2005, between The Williams Companies, Inc. and Williams Partners L.P. (attached as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).

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Exhibit Number	Description
*Exhibit 10.6	Amended and Restated Credit Agreement dated as of May 20, 2005 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and the Banks, Citibank, N.A. and Bank of America, N.A., and Citicorp USA, INC. as administrative agent (attached as Exhibit 1.1 to The Williams Companies, Inc. s current report on Form 8-K (File No. 001-04174) filed with the SEC on May 26, 2005).
*Exhibit 10.7	Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (attached as Exhibit 10.7 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005).
*Exhibit 10.8	Base Contract for Sale and Purchase of Natural Gas between Williams Natural Gas Liquids, Inc. and Williams Power Company, Inc., dated August 15, 2005 (attached as Exhibit 10.7 to Williams Partners L.P. s quarterly report on Form 10-Q filed with the SEC on September 22, 2005).
*#Exhibit 10.9	Director Compensation Policy dated November 29, 2005 (attached as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on December 1, 2005).
*#Exhibit 10.10	Form of Grant Agreement for Restricted Units (attached as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on December 1, 2005).
*Exhibit 21	List of subsidiaries of Williams Partners L.P. (attached as Exhibit 21.1 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005)
+Exhibit 23	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
+Exhibit 24	Power of attorney together with certified resolution.
+Exhibit 31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
+Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
+Exhibit 32	Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer.

+Exhibit 99.1	Pre-approval policy with respect to audit and non-audit services of the audit committee of the board of directors of Williams Partners GP LLC.
+Exhibit 99.2	Williams Partners GP LLC Financial Statements.

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

+ Filed herewith.

Confidential treatment requested for omitted portions.

Management contract or compensatory plan or arrangement.

(c) *Discovery Producer Services LLC financial statements and notes thereto*

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REPORT OF INDEPENDENT AUDITORS

To the Management Committee of
Discovery Producer Services LLC

We have audited the accompanying consolidated balance sheets of Discovery Producer Services LLC as of December 31, 2005 and 2004, and the related consolidated statements of income and comprehensive income, members capital, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company 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 auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and 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 Discovery Producer Services LLC at December 31, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States.

As described in Note 4, effective January 1, 2003, Discovery Producer Services LLC adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.*

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2005

DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2005	2004
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 21,378	$ 55,222
Accounts receivable:		
Affiliate	31,448	4,399
Other	14,451	5,761
Inventory	924	840
Other current assets	2,324	1,312
Total current assets	70,525	67,534
Restricted cash	44,559	
Property, plant and equipment, net	344,743	356,385
Total assets	$ 459,827	$ 423,919
LIABILITIES AND MEMBERS CAPITAL		
Current liabilities:		
Accounts payable:		
Affiliate	$ 9,334	$ 682
Other	26,796	14,622
Accrued liabilities	6,205	14,197
Other current liabilities	2,735	2,071
Total current liabilities	45,070	31,572
Noncurrent accrued liabilities	1,121	702
Commitments and contingent liabilities (Note 7)		
Members capital	413,636	391,645
Total liabilities and members capital	$ 459,827	$ 423,919

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Revenues:			
Product sales:			
Affiliate	$ 70,848	$ 57,838	$ 54,145
Third-party	4,271	1,611	1,943
Gas and condensate transportation services:			
Affiliate	1,908	3,966	4,611
Third-party	13,498	12,052	13,225
Gathering and processing services:			
Affiliate	3,585	6,962	7,549
Third-party	26,133	14,168	16,974
Other revenues	2,502	3,279	4,731
Total revenues	122,745	99,876	103,178
Costs and expenses:			
Product cost and shrink replacement:			
Affiliate	7,911	423	7,832
Third-party	56,556	44,932	35,082
Operating and maintenance expenses:			
Affiliate	3,355	3,098	3,035
Third-party	6,810	14,756	12,794
Depreciation and accretion	24,794	22,795	22,875
General and administrative expenses affiliate	2,053	1,424	1,400
Taxes other than income	1,151	1,382	1,602
Other net	(33)	(54)	(101)
Total costs and expenses	102,597	88,756	84,519
Operating income	20,148	11,120	18,659
Interest expense			9,611
Interest income	(1,685)	(550)	
Foreign exchange loss	1,005		
Income before cumulative effect of change in accounting principle	20,828	11,670	9,048
Cumulative effect of change in accounting principle	(176)		(267)
Net income	$ 20,652	$ 11,670	$ 8,781
Other comprehensive income:			
Cash flow hedging activities:			

Losses reclassified to earnings during year	$	$	$ 5,196
Unrealized losses during year			(291)
Other comprehensive income			4,905
Comprehensive income	$ 20,652	$ 11,670	$ 13,686

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED STATEMENT OF MEMBERS CAPITAL

	Williams Energy LLC	Williams Operating Partners LLC	Duke Energy Field Services, LLC	Eni BB Pipelines LLC	Accumulated Other Comprehensive Income (Loss)	Total
			(In thousands)			
Balance, December 31, 2002	$ 58,541	$	$ 39,028	$ 19,515	$ (4,905)	$ 112,179
Contributions	127,055		84,695	42,360		254,110
Net income 2003	4,391		2,927	1,463		8,781
Other comprehensive (loss)					4,905	4,905
Balance, December 31, 2003	189,987		126,650	63,338		379,975
Net income 2004	5,835		3,890	1,945		11,670
Balance, December 31, 2004	195,822		130,540	65,283		391,645
Contributions	16,269	24,400	7,634			48,303
Distributions	(30,030)	(1,280)	(15,654)			(46,964)
Net income 2005	8,063	4,651	6,909	1,029		20,652
Sale of Eni 16.67% interest to subsidiaries of Williams Energy LLC	66,312			(66,312)		
Sale of Williams Energy LLC and subsidiaries 40% interest to Williams Operating Partners LLC	(142,761)	142,761				
Sale of Williams Energy LLC 6.67% interest to Duke Energy Field Services LLC	(25,869)		25,869			
Balance, December 31, 2005	$ 87,806	$ 170,532	$ 155,298	$	$	$ 413,636

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2005	2004	2003
	(In thousands)		
OPERATING ACTIVITIES:			
Income before cumulative effect of change in accounting principle	$ 20,828	$ 11,670	$ 9,048
Adjustments to reconcile to cash provided by operations:			
Depreciation and accretion	24,794	22,795	22,875
Cash provided (used) by changes in assets and liabilities:			
Accounts receivable	(35,739)	(1,658)	7,860
Inventory	(84)	(240)	(229)
Other current assets	(1,012)	(1)	(761)
Accounts payable	29,355	1,256	(1,415)
Other current liabilities	664	(668)	2,223
Accrued liabilities	(7,992)	2,469	4,424
Net cash provided by operating activities	30,814	35,623	44,025
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(12,906)	(46,701)	(14,746)
Change in accounts payable capital expenditures	(8,532)	7,586	2,673
Increase in restricted cash	(44,559)		
Net cash used by investing activities	(65,997)	(39,115)	(12,073)
FINANCING ACTIVITIES:			
Payments of long-term debt			(253,701)
Distributions to members	(46,964)		
Capital contributions	48,303		254,110
Net cash provided by financing activities	1,339		409
Increase (decrease) in cash and cash equivalents	(33,844)	(3,492)	32,361
Cash and cash equivalents at beginning of period	55,222	58,714	26,353
Cash and cash equivalents at end of period	$ 21,378	$ 55,222	$ 58,714
Supplemental Disclosure of Cash Flow Information			
Cash paid during the year for interest	$	$	$ 9,855

See accompanying notes to consolidated financial statements.

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DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Description of Business

Our company consists of Discovery Producer Services LLC (DPS), a Delaware limited liability company formed on June 24, 1996, and its wholly owned subsidiary, Discovery Gas Transmission LLC (DGT), a Delaware limited liability company formed on June 24, 1996. DPS was formed for the purpose of constructing and operating a 600 million cubic feet per day (MMcf/d) cryogenic natural gas processing plant near Larose, Louisiana and a 32,000 barrel per day (bpd) natural gas liquids fractionator plant near Paradis, Louisiana. DGT was formed for the purpose of constructing and operating a natural gas pipeline from offshore deep water in the Gulf of Mexico to DPS s gas processing plant in Larose, Louisiana. The pipeline has a design capacity of 600 million cubic feet per day and consists of approximately 173 miles of pipe. DPS has since connected several laterals to the DGT pipeline to expand its presence in the Gulf. Herein, DPS and DGT are collectively referred to in the first person as we, us or our and sometimes as the Company .

Until April 14, 2005, we were owned 50 percent by Williams Energy, L.L.C. (a wholly owned subsidiary of The Williams Companies, Inc.), 33.33 percent by Duke Energy Field Services, LP (Duke) and 16.67 percent by Eni BB Pipeline, LLC (Eni) (formerly British-Borneo Pipeline LLC). Williams Energy is our operator. Herein, The Williams Companies, Inc. and its subsidiaries are collectively referred to as Williams.

On April 14, 2005, Williams acquired the 16.67 percent ownership interest in us previously held by Eni. As a result we became 66.67 percent owned by Williams and 33.33 percent owned by Duke.

On August 22, 2005, we distributed cash of $44 million to the members based on 66.67 percent ownership by Williams and 33.33 percent ownership by Duke.

On August 23, 2005, Williams Partners Operating LLC (a wholly owned subsidiary of Williams Partners L.P.) (WPZ) acquired a 40 percent interest in us previously held by Williams Energy. As a result we became 40 percent owned by WPZ, 26.67 percent owned by Williams and 33.33 percent owned by Duke. In connection with this Williams, Duke and WPZ amended our limited liability company agreement including provisions for (1) quarterly distributions of available cash, as defined in the amended agreement and (2) pursuit of capital projects for the benefit of one or more of our members when there is not unanimous consent.

On December 22, 2005, Duke acquired 6.67 percent interest in us previously held by Williams Energy. As a result we became 40 percent owned by WPZ, 20 percent owned by Williams and 40 percent owned by Duke.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation. The consolidated financial statements have been prepared based upon accounting principles generally accepted in the United States and include the accounts of DPS and its wholly owned subsidiary, DGT. Intercompany accounts and transactions have been eliminated.

Reclassifications. Certain prior years amounts have been reclassified to conform with the current year presentation. These include the reclassification of certain costs charged by Williams under operation and maintenance agreements. We have reclassified these costs, which relate to accounting services, computer systems and management services, to General and administrative expenses affiliate on the Consolidated Statements of Income.

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

DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash and Cash Equivalents. Cash and cash equivalents include demand and time deposits, certificates of deposit and other marketable securities with maturities of three months or less when acquired.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. No allowance for doubtful accounts is recognized at the time the revenue that generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. There was no allowance for doubtful accounts at December 31, 2005, and 2004.

Gas Imbalances. In the course of providing transportation services to customers, DGT may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. This results in gas transportation imbalance receivables and payables which are recovered or repaid in cash, based on market-based prices, or through the receipt or delivery of gas in the future and are recorded in the balance sheet. Settlement of imbalances requires agreement between the pipelines and shippers as to allocations of volumes to specific transportation contracts and the timing of delivery of gas based on operational conditions. In accordance with its tariff, DGT is required to account for this imbalance (cash-out) liability/receivable and refund or invoice the excess or deficiency when the cumulative amount exceeds $400,000. To the extent that this difference, at any year end, is less than $400,000 such amount would carry forward and be included in the cumulative computation of the difference evaluated at the following year end.

Inventory. Inventory includes fractionated products at our Paradis facility and is carried at the lower cost of market.

Restricted cash. Restricted cash within non-current assets relates to escrow funds contributed by our members for the construction of the Tahiti pipeline lateral expansion. The restricted cash is classified as non-current because the funds will be used to construct a long-term asset. The restricted cash is primarily invested in short-term money market accounts with financials institutions.

Property, Plant and Equipment. Property, plant and equipment are carried at cost. We base the carrying value of these assets on estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values. The natural gas and natural gas liquids maintained in the pipeline facilities necessary for their operation (line fill) are included in property, plant and equipment.

Depreciation for DPS s facilities and equipment is computed primarily using the straight-line method with 25-year lives. Depreciation for DGT s facilities and equipment is computed using the straight-line method with 15-year lives.

We record an asset and a liability equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in operating income.

Revenue Recognition. Revenue for sales of products are recognized in the period of delivery and revenues from the gathering, transportation and processing of gas are recognized in the period the service is provided based on contractual terms and the related natural gas and liquid volumes. DGT is subject to Federal Energy Regulatory Commission (FERC) regulations, and accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending cases. DGT records rate refund liabilities considering regulatory proceedings by DGT and other third parties, advice of counsel, and estimated total exposure as

DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

discounted and risk weighted, as well as collection and other risks. There were no rate refund liabilities accrued at December 31, 2005 or 2004.

Derivative Instruments and Hedging Activities. The accounting for changes in the fair value of a derivative depends upon whether we have designated it in a hedging relationship and, further, on the type of hedging relationship. To qualify for designation in a hedging relationship, specific criteria must be met and the appropriate documentation maintained in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. We establish hedging relationships pursuant to our risk management policies. We initially and regularly evaluate the hedging relationships to determine whether they are expected to be, and have been, highly effective hedges. If a derivative ceases to be a highly effective hedge, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized in earnings each period.

We entered into interest rate swap agreements to reduce the impact of changes in interest rates on our floating rate debt. These instruments were designated as cash flow hedges under SFAS No. 133. The effective portion of the change in fair value of the derivatives is reported in other comprehensive income and reclassified into earnings and included in interest expense in the period in which the hedged item affects earnings. There are no amounts excluded from the effectiveness calculation, and there was no ineffective portion of the change in fair value in 2003. The interest rate swap expired on December 31, 2003, and we have no other derivative instruments.

Impairment of Long-Lived Assets. We evaluate long-lived assets for impairment on an individual asset or asset group basis when events or changes in circumstances indicate, in our management s judgment, that the carrying value of such assets may not be recoverable. When such a determination has been made, we compare our management s estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether impairment has occurred. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

Judgments and assumptions are inherent in our 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. These judgments and assumptions include such matters as the estimation of additional tie-ins of customers, strategic value, rate adjustments, and capital expenditures. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Accounting for Repair and Maintenance Costs. We expense the cost of maintenance and repairs as incurred; significant improvements are capitalized and depreciated over the remaining useful life of the asset.

Capitalization of Interest. We capitalize interest on major projects during construction. Interest is capitalized on borrowed funds. Rates are based on the average interest rate on debt.

Income Taxes. For federal tax purposes, we have elected to be treated as a partnership with each member being separately taxed on its ratable share of our taxable income. This election, to be treated as a pass-through entity, also applies to our wholly owned subsidiary, DGT. Therefore, no income taxes or deferred income taxes are reflected in the consolidated financial statements.

Foreign Currency Transactions. Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transaction gains or losses which are reflected in the Consolidated Statements of Income.

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DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Recent Accounting Standards. In December 2004, the Financial Accounting Standards Board (FASB) issued revised SFAS No. 123, Share-Based Payment. The Statement requires that compensation costs for all share-based awards to employees be recognized in the financial statements at fair value. The Statement, as issued by the FASB, was to be effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. However, in April 2005, the Securities and Exchange Commission (SEC) adopted a new rule that delayed the effective date for revised SFAS No. 123 to the beginning of the next fiscal year that begins after June 15, 2005. We intend to adopt the revised Statement as of January 1, 2006. Payroll costs directly charged to us by Williams and general and administrative costs allocated to us by Williams (see Note 3) will include such compensation costs beginning January 1, 2006. Our adoption of this Statement will not have a material impact on our Consolidated Financial Statements.

In November 2004, the FASB issued SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4, which will be applied prospectively for inventory costs incurred in fiscal years beginning after June 15, 2005. The Statement amends Accounting Research Bulletin (ARB) No. 43, Chapter 4, Inventory Pricing, to clarify that abnormal amounts of certain costs should be recognized as current period charges and that the allocation of overhead costs should be based on the normal capacity of the production facility. The impact of this Statement on our Consolidated Financial Statements will not be material.

In December 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, which is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005, and will be applied prospectively. The Statement amends APB Opinion No. 29, Accounting for Nonmonetary Transactions. The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but includes certain exceptions to that principle. SFAS No. 153 amends APB Opinion 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.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3, which is effective prospectively for reporting a change in accounting principle for fiscal years beginning after December 15, 2005. The Statement changes the reporting of a change in accounting principle to require retrospective application to prior periods financial statements, except for explicit transition provisions provided for in any existing accounting pronouncements, including those in the transition phase when SFAS No. 154 becomes effective.

Note 3. Related Party Transactions

We have no employees. Pipeline and plant operations were performed under operation and maintenance agreements with Williams. Under this agreement, we reimburse Williams for direct payroll and employee benefit costs incurred on our behalf. Most costs for materials, services and other charges are third-party charges and are invoiced directly to us. Additionally, we purchase a portion of the natural gas from Williams to meet our fuel and shrink requirements at our processing plant. These costs are presented as Operating and maintenance expenses affiliate and Product costs and shrink replacement affiliate on the Consolidated Statements of Income.

We pay Williams a monthly operation and management fee to cover the cost of accounting services, computer systems and management services provided to us. This fee is presented as General and administrative expenses affiliate on the Consolidated Statements of Income.

We also pay Williams a project management fee to cover the cost of managing capital projects. This fee is determined on a project by project basis and is capitalized as part of the construction costs.

DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the payroll costs and project fees charged to us by Williams and capitalized are as follows:

	Years Ended December 31,		
	2005	2004	2003
Capitalized labor	$ 351	$ 288	$ 204
Capitalized project fee	115	854	147
	$ 466	$ 1,142	$ 351

We have various business transactions with our members and other subsidiaries and affiliates of our members, including an agreement with Williams pursuant to which Williams markets the NGLs and natural gas to which we take title. Under the terms of this agreement, Williams purchases the NGLs and excess natural gas and resells it, for its own account, to end users. During 2005, we had transactions with Texas Eastern Corporation, a subsidiary of Duke. These transactions primarily included processing and sales of natural gas liquids and transportation of gas and condensate. We have business transactions with Eni that primarily include processing and transportation of gas and condensate. The following table summarizes these related-party revenues during 2005, 2004 and 2003.

	Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Eni*	$ 2,830	$ 10,928	$ 12,160
Texas Eastern Corporation	2,663		
Williams	70,848	57,838	54,145
Total	$ 76,341	$ 68,766	$ 66,305

* Through April 14, 2005

Note 4. Property, Plant and Equipment

Property, plant and equipment consisted of the following at December 31, 2005 and 2004:

	2005	2004
	(In thousands)	
Property, plant and equipment:		
Construction work in progress	$ 5,444	$ 11,739
Buildings	4,406	4,393
Land and land rights	1,530	1,165
Transportation lines	302,252	286,661
Plant and other equipment	198,837	195,429

		512,469		499,387
Less accumulated depreciation and amortization		167,726		143,002
	$	344,743	$	356,385

Commitments for construction and acquisition of property, plant and equipment for Tahiti are approximately $64 million at December 31, 2005.

We adopted SFAS No. 143, Accounting for Asset Retirement Obligations on January 1, 2003. As a result, we recorded a liability of $549,000 representing the present value of expected future asset retirement obligations at January 1, 2003, and a decrease to earnings of $267,000 reflected as a cumulative effect of a change in accounting principle.

DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effective December 31, 2005, we adopted Financial Accounting Standards Board Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability s fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. As required by the new standard, we reassessed the estimated remaining life of all our assets with a conditional ARO. We recorded additional liabilities totaling $327,000 equal to the present value of expected future asset retirement obligations at December 31, 2005. The liabilities are slightly offset by a $151,000 increase in property, plant and equipment, net of accumulated depreciation, recorded as if the provisions of the Interpretation had been in effect at the date the obligation was incurred. The net $176,000 reduction to earnings is reflected as a cumulative effect of a change in accounting principle for the year ended 2005. If the Interpretation had been in effect at the beginning of 2003, the impact to our income from continuing operations and net income would have been immaterial.

The obligations relate to an offshore platform and our onshore processing and fractionation facilities. At the end of the useful life of each respective asset, we are legally or contractually obligated to dismantle the offshore platform, remove the onshore facilities and related surface equipment and restore the surface of the property.

A rollforward of our asset retirement obligation for 2005 and 2004 is presented below.

	2005	2004
	(In thousands)	
Balance, January 1	$ 702	$ 621
Accretion expense	92	81
FIN No. 47 revisions	327	
Balance, December 31	$ 1,121	$ 702

Note 5. Leasing Activities

We lease the land on which the Paradis fractionator plant and the Larose processing plant are located. The initial terms of the leases are 20 years with renewal options for an additional 30 years. We entered into a 10 year leasing agreement for pipeline capacity from Texas Eastern Transmission, LP, as part of our Market Expansion project which began in June 2005 (see Note 7). The lease includes renewal options and options to increase capacity which would also increase rentals. The future minimum annual rentals under these non-cancelable leases as of December 31, 2005 are payable as follows:

	(In thousands)
2006	$ 854
2007	854
2008	858
2009	858
2010	858
Thereafter	4,109
	$ 8,391

Total rent expense for 2005, 2004 and 2003, including a cancelable platform space lease and month-to-month leases, was $994,610, $866,000 and $1,050,000, respectively.

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DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 6. Financial Instruments and Concentrations of Credit Risk

Financial Instruments Fair Value

We used the following methods and assumptions to estimate the fair value of financial instruments:

Cash and cash equivalents. The carrying amounts reported in the balance sheets approximate fair value due to the short-term maturity of these instruments.

Restricted cash. The carrying amounts reported in the balance sheets approximate fair value as these instruments have interest rates approximating market.

	2005		2004	
Asset	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
	(In thousands)			
Cash and cash equivalents	$ 21,378	$ 21,378	$ 55,222	$ 55,222
Restricted cash	44,559	44,559		

Concentrations of Credit Risk

Our cash equivalents and restricted cash consist of high-quality securities placed with various major financial institutions with credit ratings at or above AA by Standard & Poor s or Aa by Moody s Investor s Service.

Substantially all of our accounts receivable result from gas transmission services for and natural gas liquids sales to our two largest customers at December 31, 2005 and 2004. This concentration of customers may impact our overall credit risk either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly. Our credit policy and the relatively short duration of receivables mitigate the risk of uncollected receivables. We did not incur any credit losses on receivables during 2005 and 2004.

Major Customers. Williams and Eni accounted for approximately $70.8 million (58 percent) and $8.5 million (7 percent), respectively, of our total revenues in 2005, and $57.8 million (58 percent) and $10.9 million (11 percent), respectively, of our total revenues in 2004. Three customers, Williams, Eni and Pogo Producing Company accounted for approximately $54 million (52 percent), $12.2 million (12 percent) and $12 million (12 percent), respectively, of our total revenues in 2003.

Note 7. Rate and Regulatory Matters and Contingent Liabilities

Rate and Regulatory Matters. In 2002, DGT filed a request with the FERC to change the lost and unaccounted-for gas percentage to be allocated to shippers from 0.5 percent to 0.1 percent to be effective for the period from July 1, 2002 to June 30, 2003. On June 26, 2002, the FERC approved DGT s request. Additionally, DGT filed to reduce the lost and unaccounted-for gas percentage to zero to be effective for the period from July 1, 2003 to June 30, 2004. On June 19, 2003, the FERC approved this request. On June 1, 2004, DGT filed to maintain a lost and unaccounted-for percentage of zero for the period from July 1, 2004 to June 30, 2005 due to the continued absence of system gas losses. On June 22, 2004, the FERC approved this request. In this filing, DGT explained that management determined the reasons for the gas gains and established new procedures in July 2003 that significantly reduced the amount of gains occurring thereafter. On April 28, 2005, DGT filed to maintain a lost and unaccounted-for gas percentage of zero for the period from July 1, 2005 to June 30, 2006. DGT also filed to retain net system gains that are unrelated to the lost and unaccounted-for gas over-recovered from its shippers. These system gas gains totaled approximately $2.5 million, $2.5 million and $5.5 million respectively in 2005, 2004, and 2003. Certain shippers protested the net system gains filing and the FERC requested additional information in a May 27, 2005 Letter Order. DGT

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DISCOVERY PRODUCER SERVICES LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

responded to the information request and on October 31, 2005, the FERC accepted the filing and no requests for rehearing were filed. As a result, we recognized system gains for 2002 2004 of $10.7 million in 2005. As of December 31, 2005 and 2004, DGT has deferred amounts of $6 million and $14.2 million, respectively, included in current accrued liabilities in the accompanying Consolidated Balance Sheets representing amounts collected from customers pursuant to prior years lost and unaccounted for gas percentage and unrecognized net system gains for 2005.

On July 23, 2003, DGT applied to the FERC for a Certificate of Public Convenience and Necessity authorizing DGT s market expansion to acquire, lease or construct and/or to own and operate certain new delivery points, pipeline, compression services and metering and appurtenant facilities to enable DGT to deliver natural gas to four additional delivery points to new markets in southern Louisiana. This application was amended on December 30, 2003. On the same dates, DPS applied to the FERC and amended its application for a Limited Jurisdiction Certificate authorizing DPS to provide the compression services to DGT to enable DGT to provide service through the Market Expansion facilities. The capital cost of the expansion facilities was approximately $11 million. On May 6, 2004, the FERC granted DGT s and DPS s applications. On July 13, 2004, the FERC granted an additional approval on a rate design issue requested by DGT. On January 6, 2005, the FERC granted DGT permission to commence construction of the Market Expansion facilities. The Market Expansion facilities became operational in June 2005.

On November 25, 2003, the FERC issued Order No. 2004 promulgating new standards of conduct applicable to natural gas pipelines. On August 10, 2004, the FERC granted DGT a partial exemption allowing the continuation of DGT s current ownership structure and management subject to compliance with many of the other standards of conduct. DGT continues to evaluate the effect of the partial exemption and the compliance with the remaining requirements. The effect of complying with the new standards is not expected to have a material effect on the consolidated financial statements.

On October 11, 2005, DGT applied to the FERC for permission to construct and operate facilities to allow temporary re-routing of gas to DGT from other facilities that were impacted by Hurricane Katrina. The FERC granted emergency exemptions and waivers permitting such actions the same day, allowing emergency service for up to one year or until certain third-party processing facilities were restored to service. DGT conducted two open seasons for shippers wishing to take advantage of the new service.

On January 16, 2006, DPS and DGT received notice of a claim by POGO Producing Company (POGO) relating to the results of a POGO audit performed in April 2004. POGO claims that DPS and DGT overcharged POGO and its working interest owners of approximately $600,000 relating to condensate transportation and handling during 2000 2004. The underlying agreements limit audit claims to a two-year period from the date of the audit, and DPS and DGT dispute the validity of the claim.

Environmental Matters. We are subject to extensive federal, state and local environmental laws and regulations which affect our operations related to the construction and operation of our facilities. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions as to future compliance. We have not been notified and are not currently aware of any noncompliance under the various environmental laws and regulations.

Other. We are party to various other claims, legal actions and complaints arising in the ordinary course of business. Litigation, arbitration and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our future financial position.

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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.

Williams Partners L.P.
(Registrant)

By: Williams Partners GP LLC,
its general partner

By: /s/ William H. Gault

William H. Gault
Attorney-in-fact

Date: March 3, 2006

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

Signature	Title	Date
* Steven J. Malcolm	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 3, 2006
* Donald R. Chappel	Chief Financial Officer and Director (Principal Financial Officer)	March 3, 2006
* Ted T. Timmermans	Chief Accounting Officer and Controller (Principal Accounting Officer)	March 3, 2006
* Alan S. Armstrong	Chief Operating Officer and Director	March 3, 2006
* Bill Z. Parker	Director	March 3, 2006
* Alice M. Peterson	Director	March 3, 2006
* Thomas C. Knudson	Director	March 3, 2006

*	Director	March 3, 2006
Phillip D. Wright		
By: /s/ William H. Gault		March 3, 2006
William H. Gault *Attorney-in-fact*		

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INDEX TO EXHIBITS

The exhibits listed below are filed as part of this annual report:

Exhibit Number	Description
*Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (attached as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on May 2, 2005).
*Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (attached as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on May 2, 2005).
*Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (attached as Exhibit 3.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (attached as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
* Exhibit 10.1	Fractionation Agreement dated July 18, 1997, by and between MAPCO Natural Gas Liquids Inc. and Amoco Oil Company (attached as Exhibit 10.6 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005).
*Exhibit 10.2	Omnibus Agreement among Williams Partners L.P., Williams Energy Services, LLC, Williams Energy, L.L.C., Williams Partners Holdings LLC, Williams Discovery Pipeline LLC, Williams Partners GP LLC, Williams Partners Operating LLC and (for purposes of Articles V and VI thereof only) The Williams Companies, Inc. (attached as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*#Exhibit 10.3	Williams Partners GP LLC Long-Term Incentive Plan (attached as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*Exhibit 10.4	Contribution, Conveyance and Assumption Agreement, dated August 23, 2005, by and among Williams Partners L.P., Williams Energy, L.L.C., Williams Partners GP LLC, Williams Partners Operating LLC, Williams Energy Services, LLC, Williams Discovery Pipeline LLC, Williams Partners Holdings LLC and Williams Natural Gas Liquids, Inc. (attached as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K filed with the SEC on August 26, 2005).

*Exhibit 10.5	Working Capital Loan Agreement, dated August 23, 2005, between The Williams Companies, Inc. and Williams Partners L.P. (attached as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on August 26, 2005).
*Exhibit 10.6	Amended and Restated Credit Agreement dated as of May 20, 2005 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and the Banks, Citibank, N.A. and Bank of America, N.A., and Citicorp USA, INC. as administrative agent (attached as Exhibit 1.1 to The Williams Companies, Inc. s current report on Form 8-K (File No. 001-04174) filed with the SEC on May 26, 2005).
*Exhibit 10.7	Third Amended and Restated Limited Liability Company Agreement for Discovery Producer Services LLC (attached as Exhibit 10.7 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005).
*Exhibit 10.8	Base Contract for Sale and Purchase of Natural Gas between Williams Natural Gas Liquids, Inc. and Williams Power Company, Inc., dated August 15, 2005 (attached as Exhibit 10.7 to Williams Partners L.P. s quarterly report on Form 10-Q filed with the SEC on September 22, 2005).

Exhibit Number	Description
*#Exhibit 10.9	Director Compensation Policy dated November 29, 2005 (attached as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on December 1, 2005).
*#Exhibit 10.10	Form of Grant Agreement for Restricted Units (attached as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599) filed with the SEC on December 1, 2005).
*Exhibit 21	List of subsidiaries of Williams Partners L.P. (attached as Exhibit 21.1 to Amendment No. 1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517) filed with the SEC on June 24, 2005).
+Exhibit 23	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
+Exhibit 24	Power of attorney together with certified resolution.
+Exhibit 31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
+Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
+Exhibit 32	Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer.
+Exhibit 99.1	Pre-approval policy with respect to audit and non-audit services of the audit committee of the board of directors of Williams Partners GP LLC.
+Exhibit 99.2	Williams Partners GP LLC Financial Statements.

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

\+ Filed herewith.

Confidential treatment requested for omitted portions.

\# Management contract or compensatory plan or arrangement.

(c) *Discovery financials*