Enterprise GP Holdings L.P.
Form 10-K
February 27, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2005

OR

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: 1-32610

ENTERPRISE GP HOLDINGS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**13-4297064** (I.R.S. Employer Identification No.)
2727 North Loop West, Houston, Texas (Address of Principal Executive Offices)	**77008-1044** (Zip Code)

(713) 426-4500
(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
Units	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes o No x

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 x

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 x 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. x

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 [ ] Accelerated filer [ ] Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

Enterprise GP Holdings L.P. (EPE) completed its initial public offering of units in August 2005. As such, the aggregate market value disclosure required on the cover page of Form 10-K has not been provided. There were 88,884,116 units of EPE outstanding at February 15, 2006.

ENTERPRISE GP HOLDINGS L.P.

TABLE OF CONTENTS

		Page Number
PART I		
Item 1.	Business	1
Item 1A.	Risk Factors	16
Item 1B.	Unresolved Staff Comments	34
Item 2.	Properties	34
Item 3.	Legal Proceedings	45
Item 4.	Submission of Matters to a Vote of Security Holders	45
PART II		
Item 5.	Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	46
Item 6.	Selected Financial Data	47
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	48
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	81
Item 8.	Financial Statements and Supplementary Data	85
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	165
Item 9A.	Controls and Procedures	165
Item 9B.	Other Information	166
PART III		
Item 10.	Directors and Executive Officers of the Registrant	167
Item 11.	Executive Compensation	174
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	177
Item 13.	Certain Relationships and Related Transactions	181
Item 14.	Principal Accountant Fees and Services	188
PART IV		
Item 15.	Exhibits and Financial Statement Schedules	190
Financial Statements		85
Signatures		197
Index to Exhibits		198

Significant Relationships Referenced in this Annual Report

Unless the context requires otherwise, references to *we*, *us*, *our* or *Enterprise GP Holdings L.P.* are intended to mean and include the business and operations of Enterprise GP Holdings L.P., the parent company, as well as its consolidated subsidiaries, which include Enterprise Products GP, LLC and Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to *the parent company* are intended to mean and include Enterprise GP Holdings L.P., individually as the parent company, and not on a consolidated basis.

References to *EPE Holdings* mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings L.P.

References to *Enterprise Products Partners* mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to *Enterprise Products GP* mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners L.P.

References to *EPCO* mean EPCO, Inc., which is a related party affiliate to all of the foregoing named entities.

PART I

Item 1. ***Business.***

GENERAL

We are the sole member of Enterprise Products GP. The primary business purpose of Enterprise Products GP is to manage the affairs and operations of Enterprise Products Partners, a North American midstream energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), and crude oil, and is an industry leader in the development of pipeline and other midstream infrastructure in the continental United States and Gulf of Mexico. Enterprise Products Partners conducts substantially all of its business through a wholly owned subsidiary, Enterprise Products Operating L.P. (the Operating Partnership).

We are a publicly traded Delaware limited partnership, the units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPE. We were formed in April 2005 and completed our initial public offering of 14,216,784 units in August 2005. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008 and our telephone number is (713) 426-4500.

We are owned 99.99% by our limited partners and 0.01% by EPE Holdings. We, EPE Holdings, Enterprise Products GP and Enterprise Products Partners are under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO. We and Enterprise Products GP have no independent operations outside those of Enterprise Products Partners.

As a registrant, we file certain documents electronically with the U.S. Securities and Exchange Commission (SEC), including annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time-to-time, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.enterprisegp.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our investor relations department at (713) 426-4504 for paper copies of these reports free of charge.

As generally used in the energy industry and in this document, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British Thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
Mdth	= thousand dekatherms
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Mcf	= thousand cubic feet

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report contains various forward-looking statements and information that are based on our beliefs and those of EPE Holdings, as well as assumptions made by us and information currently available to us. When used in this document, words such as anticipate, project, expect, plan, goal, forecast, intend, could, believe, may and similar expressions and statements regarding our plans and objectives for future o are intended to identify forward-looking statements. Although we and EPE Holdings believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor EPE Holdings can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

BUSINESS STRATEGY

Our primary objective is to increase cash available for distributions to our unitholders and, accordingly, the value of our limited partner interests. In recent years, major independent oil and gas and other energy companies have divested significant midstream assets. Additionally, there have been several transactions involving the sale of general partner interests in publicly traded partnerships. Asset rationalization among energy companies and transactions involving the sale of general partner interests is expected to continue. Our business strategy seeks to capitalize on these trends by:

managing Enterprise Products Partners for the successful execution of its business strategy;

pursuing acquisitions of assets and businesses that may or may not be related to Enterprise Products Partners business in accordance with our business opportunity agreements; and

acquiring general partner interests and associated incentive distribution rights and limited partner interests in other publicly traded partnerships.

PARENT COMPANY ASSETS

The parent company s cash generating assets consist entirely of its partnership interests in Enterprise Products Partners, from which it receives quarterly cash distributions. At February 15, 2006, the parent company s assets consist of the following partnership interests in Enterprise Products Partners:

a 100% ownership interest in Enterprise Products GP, which owns a 2% general partner interest in Enterprise Products Partners that entitles Enterprise Products GP to receive 2% of the cash distributed by Enterprise Products Partners;

the incentive distribution rights associated with Enterprise Products GP's general partner interest in Enterprise Products Partners; and

13,454,498 common units of Enterprise Products Partners, representing an approximate 3.4% limited partner interest in Enterprise Products Partners.

As an incentive, Enterprise Products GP s percentage interest in Enterprise Products Partners quarterly cash distributions is increased after certain specified target levels of distribution rates are met by Enterprise Products Partners. Enterprise Products GP s quarterly incentive distribution thresholds are as follows:

2% of quarterly cash distributions up to $0.253 per unit paid by Enterprise Products Partners;
15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit paid by Enterprise Products Partners; and
25% of quarterly cash distributions that exceed $0.3085 per unit paid by Enterprise Products Partners.

Enterprise Products GP received incentive distributions from Enterprise Products Partners of $63.9 million, $32.4 million and $19.7 million in 2005, 2004 and 2003, respectively.

The following table summarizes the key components of the results of operations of the parent company since its formation in April 2005 (in thousands).

Equity in income of unconsolidated affiliates	$	24,507
Interest expense	$	3,445
Net income	$	20,631

For additional information regarding the financial results of the parent company, please see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

RECENT DEVELOPMENTS

For information regarding significant events affecting us during 2005, please read *Recent Developments* included under Item 7 of this annual report, which is incorporated by reference into this Item 1.

In September 2004, we completed the GulfTerra Merger transactions, whereby, among other transactions, GulfTerra Energy Partners, L.P. (GulfTerra) merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra s general partner (GulfTerra GP) became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso Corporation (El Paso) that are located in South Texas.

SEGMENT DISCUSSION

Our midstream asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Offshore Pipelines & Services; and (iv) Petrochemical Services. Our business segments are generally organized and managed along our asset base according to the type of services rendered (or technology employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced services rendered, seasonality, competition and regulation. Our results of operations and financial condition are subject to a variety of risks. For information regarding our key risk factors, please read Item 1A of this annual report. For listings and descriptions of our principal plant, pipeline and other properties by segment, please read Item 2 of this annual report.

For information regarding our general revenue recognition policies and other segment-related matters, please read Notes 4 and 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental and other matters. For a discussion of the principal effects of regulation on each of our business segments, please read *Regulation and Environmental* within each of the following segment disclosures. For a general discussion of environmental matters, please read *Other Matters* *Other Environmental* included within this Item 1.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,810 miles and related storage facilities including our Mid-America Pipeline System, Seminole Pipeline and Dixie Pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives, and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are twenty-four processing plants located in Texas, Louisiana, Mississippi and New Mexico. Natural gas produced at the wellhead and in association with crude oil contains varying amounts of NGLs. This rich natural gas in its raw form is usually not acceptable for transportation in the nation's major natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove the NGLs from the natural gas stream, enabling the natural gas to meet transmission pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemicals and motor gasoline than their value as components of the natural gas stream. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation (or separation) into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of gas processing plants are higher than the incremental value of the NGL products that would be received by NGL extraction, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (mixed percent-of-liquids and fee-based) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer s natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of proceeds contract, we share in the proceeds generated from the producer s sale of the mixed NGLs we extract on their behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we extract and retain in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs of which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our margin-band and keepwhole gas processing contracts to compensate the producer for the energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, or margin band contracts contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity financial instruments.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

NGL pipelines, storage facilities and import/export terminals. Our NGL pipeline, storage and terminalling operations include approximately 12,810 miles of NGL pipelines, 150 million barrels of underground NGL and related product storage working capacity and two import/export facilities.

Our NGL pipelines transport mixed NGLs and other hydrocarbons to fractionation plants; distribute and collect NGL products to and from petrochemical plants and refineries; and deliver propane to customers along the Dixie pipeline and certain sections of the Mid-America Pipeline System. Revenue from our NGL pipeline transportation agreements is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged to our NGL and petrochemical marketing activities, which are eliminated in consolidation). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission (FERC).

Typically, we do not take title to the products transported in our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

Our NGL and related product storage facilities are integral parts of our operations. In general, our underground storage wells are used to store our and our customers mixed NGLs, NGL products and petrochemical products. Under our NGL and related product storage agreements, we collect a fee based on the number of days a customer has volumes in storage multiplied by a storage rate for each product. Accordingly, the profitability of our storage operations is primarily dependent upon the volume of material stored and the level of fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas. Our import facility is primarily used to offload volumes to be delivered to our NGL storage and processing facilities near Mont Belvieu, Texas. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party export customers. Revenues from our import and export services are primarily based on fees per unit of volume loaded or unloaded and may also include demand charges. Accordingly, the profitability of our import and export activities primarily depends upon the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in nine NGL fractionation facilities located in Texas and Louisiana. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The three primary sources of mixed NGLs fractionated in the United States are (i) domestic natural gas processing plants, (ii) domestic crude oil refineries and (iii) imports of butane and propane mixtures. The mixed NGLs delivered from domestic natural gas processing plants and crude oil refineries to our NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck.

Recoveries of mixed NGLs by gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast and Rocky Mountain natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities by joint owners and third-party customers.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities under fee-based arrangements. These fees (typically in cents per gallon) are subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). We are exposed to fluctuations in NGL prices to the extent we fractionate volumes for customers under percent-of-liquids arrangements. Our tolling (or fee-based) customers generally retain title to the NGLs that we process for them.

Regulation and Environmental. Our Mid-America, Seminole, Dixie, Chunchula, Lou-Tex NGL pipelines and certain pipelines in which we own equity interests, along with certain pipelines of the Louisiana Pipeline System, are interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act (ICA). As interstate common carriers, these liquids pipelines must provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. We are required to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier liquids pipelines as well as the rules and regulations governing these services.

6

We believe that the rates charged for transportation services on our interstate common carrier liquids pipelines we own or have an interest in are just and reasonable under the ICA. However, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Intrastate movements of products on the Seminole, Mid-America, Belle Rose and certain pipelines of the Louisiana Pipeline System are subject to various other state laws and regulations that affect the rates we charge and the terms of service. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

Our NGL pipelines and services are subject to various safety and environmental statutes, including: the Hazardous Materials Transportation Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning, Pipeline Safety Improvement Act of 2002 and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our gas processing plants, NGL pipelines and NGL fractionation, NGL storage and related product storage operations in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquids pipelines, which include NGL and petrochemical pipelines, and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and to take measures (including repairs) to protect pipeline segments located in what the rules refer to as high consequence areas. We have ongoing programs designed to keep our pipelines in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements. For information regarding the costs of our pipeline integrity management program, please read Item 7 of this annual report.

Seasonality. Our natural gas processing and NGL fractionation operations exhibit little to no seasonal variation. Likewise, our NGL pipeline operations have not exhibited a significant degree of seasonality overall. However, propane transportation volumes are generally higher in the October through March timeframe in connection with increased use of propane for heating in the upper Midwest and southeastern United States. Our facilities located in the southern United States may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

We operate our NGL and related product storage facilities based on the needs and requirements of our customers in the NGL, petrochemical, heating and other related industries. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn for heating needs. In general, our import volumes peak during the spring and summer months and our export volumes are at their highest levels during the winter months.

In support of our commercial goals, our NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. These inventories are the result of accumulated equity NGL production volumes, imports and other spot and contract purchases. Our inventories of ethane, propane and normal butane are typically higher in summer months as each are normally in higher demand and at higher price levels during winter months. Isobutane and natural gasoline inventories are generally stable throughout the year. Our inventory cycle begins in late-February to mid-March (the seasonal low point); builds through September; remains level until early December; before being drawn through winter until the seasonal low is reached again.

Competition. Our natural gas processing business and NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources, and competition generally revolves around price, service and location.

In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate liquids pipelines companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and service.

Our competitors in the NGL and related product storage businesses area are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading volumes per hour.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Although competition for NGL fractionation services is primarily based on the fractionation fee charged, the ability of an NGL fractionator to receive mixed NGLs, store and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 17,200 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, we own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana.

Onshore natural gas pipelines. Our onshore natural gas pipeline systems provide for the gathering and transmission of natural gas from onshore developments, such as the San Juan, Barnett Shale and Permian supply basins in the Western U.S., or from offshore developments in the Gulf of Mexico through connections with offshore pipelines. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial customers or to other onshore pipelines.

Certain of our onshore natural gas pipelines generate revenue revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Intrastate natural gas pipelines (such as our Acadian Gas and Alabama Intrastate systems) may also purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers.

Our Acadian Gas and Alabama Intrastate pipelines are exposed to commodity price risk to the extent they take title to natural gas volumes through certain of their contracts. In addition, our San Juan Gathering and Permian Basin pipeline systems provide aggregating and bundling services, in which we purchase and resell natural gas for certain small producers. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices through transportation arrangements with shippers. For example, approximately 94% of the fee-based gathering arrangements of our San Juan Gathering System are calculated using a percentage of a regional price index for natural gas. We use commodity financial instruments from time to time to mitigate our exposure to risks related to commodity prices.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that are ideally situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. These facilities (our Petal Gas Storage (Petal) and Hattiesburg locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

The ability of salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. The high injection and withdrawal rates of such facilities also allow customers to take advantage of favorable natural gas prices and to quickly respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facility. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, the ability to quickly switch from full injection to full withdrawal.

Under our natural gas storage contracts, there are typically two components of revenues: (i) fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage of the storage facilities, and (ii) storage fees per unit of volume stored at the facilities.

Regulation and Environmental. Certain of our interstate natural gas pipelines and the Petal natural gas storage facility are regulated by the FERC, which approves rates, terms and other conditions under which these systems can provide services to customers. Pursuant to the FERC s jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC staff and any proposed rate increase by our offshore natural gas pipelines may be challenged by protest. The FERC s authority over companies that provide natural gas pipeline transportation or storage services also includes certification and construction of new facilities; the acquisition, extension, disposition or abandonment of facilities; the maintenance of accounts and records; the initiation, extension and discontinuation of covered services; and various other matters. As noted, our regulated natural gas pipelines have tariffs established through FERC filings that have a variety of terms and conditions, each of which affect the operations and profitability of each system. Generally, changes to these fees or terms are subject to approval by the FERC. In addition, our intrastate natural gas pipelines and natural gas storage facilities are subject to a variety of state and local regulations, including those that affect the rates we charge and terms of service.

Our onshore natural gas pipelines and storage facilities are subject to various safety and environmental statutes, including: the Natural Gas Act, the Natural Gas Policy Act, the Hazardous Materials Transportation Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning, Pipeline Safety Improvement Act of 2002 and Community Right-to-Know Act and similar state statutes. Our onshore natural gas pipelines and storage facilities are also subject to pipeline integrity programs as described under *NGL Pipelines & Services Regulation and Environmental*.

At December 31, 2005 and 2004, we had a reserve of approximately $21 million for environmental remediation costs expected to be incurred by GulfTerra over time associated with mercury meters. Remediation activities were started during 2005 and are expected to take four years to complete.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as gas-fired power generation facilities increase output for residential and commercial demand for electricity for air conditioning. Likewise, seasonality impacts the timing of injections and withdrawals at our natural gas storage facilities. In the winter months, natural gas is needed as fuel for residential and commercial heating, and during the summer months, natural gas is needed by power generation facilities due to the demand for electricity for air conditioning.

Competition. Within their market areas, our onshore natural gas pipelines compete with other onshore natural gas pipelines on the basis of price (in terms of transportation fees and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is enhanced by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being connected) to the customers we serve.

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. We believe that the locations of our natural gas storage facilities allow us to compete effectively with other companies who provide natural gas storage services.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment includes (i) approximately 1,190 miles of offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 870 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico.

Offshore natural gas pipelines. Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from production developments located in the Gulf of Mexico, primarily offshore Louisiana and Texas. Typically, these systems receive natural gas from producers, other pipelines and shippers through system interconnects and transport the natural gas to various downstream pipelines, including major interstate transmission pipelines that access multiple markets in the eastern half of the United States.

Our revenues from offshore natural gas pipelines are derived from fee-based agreements and are typically based on transportation fees per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. These transportation agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible components. We do not take title to the natural gas volumes they transported on our natural gas pipeline systems; rather, the shipper retains title and the associated commodity price risk.

Offshore oil pipelines. We own interests in several offshore oil pipeline systems, which are located in the vicinity of oil-producing areas in the Gulf of Mexico. Typically, these systems receive crude oil from offshore production developments, other pipelines or shippers through system interconnects and deliver the oil to either onshore locations or to other offshore interconnecting pipelines.

The majority of revenues from our offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along our crude oil pipelines for an index-based price (less a price differential) and sell the oil back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on a price differential per unit of volume (typically in barrels) multiplied by the volume delivered. In addition, certain of our offshore crude oil pipelines generate revenues based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to production from reserves committed under long-term contracts for the productive life of the relevant field or contracts for the purchase and sale of crude oil with terms from two to twelve months. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the amount and term of the reserve commitment by the customer.

Offshore platforms. We have ownership interests in seven multi-purpose offshore hub platforms located in the Gulf of Mexico. Offshore platforms are critical components of the offshore infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to: (i) interconnect with the offshore pipeline grid; (ii) provide an efficient means to perform pipeline maintenance; (iii) locate compression, separation, production handling and other facilities; (iv) conduct drilling operations during the initial development phase of an oil and natural gas property; and (v) process off-lease production.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees represent fixed-fees charged to customers who use our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time.

Regulation and Environmental. Certain of our offshore natural gas pipelines (primarily our High Island Offshore System) are regulated by the FERC. The jurisdiction of the FERC over these operations is similar to the FERC s jurisdiction over our interstate natural gas pipelines and the Petal natural gas storage facility as described under *Onshore Natural Gas Pipelines & Services Regulation and Environmental*.

Our offshore pipeline systems are also subject to federal regulation under the Outer Continental Shelf Lands Act (OCSLA), which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. Each of our oil pipeline systems has continuing programs of inspection and compliance designed to keep all of our facilities in compliance with pipeline safety and pollution control requirements. We believe that our oil pipeline systems are in material compliance with the applicable requirements of these regulations.

Our offshore pipelines and platforms are subject to various safety and environmental statutes, including: the OCSLA, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our oil and natural gas pipelines and offshore platform operations in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Competition. Within their market area, our offshore natural gas and oil pipelines compete with other pipelines (both regulated and unregulated systems) primarily on the basis of price (in terms of transportation fees), available capacity and connections to downstream markets. To a limited extent, our competition includes other offshore pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. We compete with other platform service providers on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, our competitors may possess greater capital resources than we have available, which could enable them to address business opportunities more quickly than us.

Petrochemical Services

Our Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes approximately 690 miles of petrochemical pipeline systems.

Propylene fractionation. Our propylene fractionation business consists primarily of four propylene fractionation facilities located in Texas and Louisiana, and approximately 620 miles of various propylene pipeline systems. These operations also include an export facility located on the Houston Ship Channel and our petrochemical marketing activities.

In general, propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade propylene can also be produced from chemical grade propylene feedstock. Chemical grade propylene is also a by-product of olefin (ethylene) production. The demand for polymer grade propylene is attributable to the manufacture of polypropylene, which has a variety of end uses, including packaging film, fiber for carpets and upholstery and molded plastic parts for appliance, automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

As part of our petrochemical marketing activities, we have several long-term polymer grade propylene sales agreements. To meet our petrochemical marketing obligations, we have entered into several agreements to purchase refinery grade propylene. To limit the exposure of our petrochemical marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Isomerization. Our isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutene and high purity isobutane. The principal uses of isobutane are for alkylate used in the production of motor gasoline, propylene oxide and in the production of methyl tertiary butyl ether (MTBE) and isooctane. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane additive production facility.

Octane enhancement. We own and operate an octane additive production facility located in Mont Belvieu, Texas designed to produce both isooctane and MTBE, which are motor gasoline additives that increase octane and are used in reformulated motor gasoline blends. This facility produces isooctane using feedstocks of high-purity isobutane and MTBE using feedstocks of high-purity isobutane and methanol. The facility s high-purity isobutane feedstock requirements are met using production from our isomerization units.

The production of MTBE was primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990, which mandated the use of reformulated gasoline in certain areas of the United States. In recent years, MTBE has been detected in water supplies. The major source of ground water contamination appears to be leaks from underground storage tanks. As a result of environmental concerns, several states enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. In addition, the Energy Policy Act of 2005 eliminates the requirement of oxygenates in reformulated motor gasoline.

As a result of such developments, we modified the facility to produce isooctane in addition to MTBE. These modifications were completed in mid-2005. We expect isooctane to be in demand by refiners to replace the amount of octane that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

Regulation and Environmental. Our interstate Lou-Tex Propylene pipeline is a common carrier pipeline regulated by the Surface Transportation Board (STB). In general, our petrochemical services operations are subject to various safety and environmental statutes, including: the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act, and similar state statutes. Our petrochemical pipelines are also subject to pipeline integrity programs as described under *NGL Pipelines & Services Regulation and Environmental*. We have ongoing programs designed to keep our storage operations in compliance with environmental and safety regulations, and we believe that our facilities are in material compliance with the applicable requirements.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher demand in the spring and summer months due to the demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, isooctane and MTBE prices have been stronger during the April to September period of each year, which corresponds with the summer driving season.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners on the Gulf Coast. Generally, the propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location.

In the isomerization market, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage infrastructure. We also compete with other octane additive manufacturing companies primarily on the basis of price.

OTHER MATTERS

Other Environmental

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These environmental laws and regulations may, in certain instances, require us to remedy the effects on the environment of the disposal or release of specified substances at current and former operating sites. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. It is possible that new information or future developments, such as increasingly strict environmental laws, could require us to reassess our potential exposure related to environmental matters. As this information becomes available, or other relevant developments occur, we will make expense accruals accordingly. For a summary of our significant environmental-related costs, please read Note 2 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Pipelines. Several federal and state environmental statutes and regulations may pertain specifically to the operations of our pipelines. Among these, the Hazardous Materials Transportation Act regulates materials capable of posing an unreasonable risk to health, safety and property when transported in commerce, and the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act authorize the development and enforcement of regulations governing pipeline transportation of natural gas and NGLs. Although federal jurisdiction is exclusive over regulated pipelines, the statutes allow states to impose additional requirements for intrastate lines if compatible with federal programs. New Mexico, Texas and Louisiana have developed regulatory programs that parallel the federal program for the transportation of natural gas and NGLs by pipelines.

Solid Waste. The operations of our pipelines and plants may generate both hazardous and nonhazardous solid wastes that are subject to the requirements of the Resource Conservation and Recovery Act and its regulations, and other federal and state statutes and regulations. Further, it is possible that some wastes that are currently classified as nonhazardous, via exemption or otherwise, perhaps including wastes currently generated during pipeline operations, may, in the future, be designated as hazardous wastes, which would then be subject to more rigorous and costly treatment, storage, transportation, and disposal requirements. Such changes in the regulations may result in additional expenditures or operating expenses for us.

Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and comparable state statutes, also known as Superfund laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that cause or contribute to the release of a hazardous substance into the environment. These persons include the current owner or operator of a site, the past owner or operator of a site, and companies that transport, dispose of, or arrange for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency or state agency, and in some cases, third parties, to take actions 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. Despite the petroleum exclusion of CERCLA Section 101(14) that currently encompasses crude oil, refined petroleum products, natural gas and NGLs, we may nonetheless handle hazardous substances, within the meaning of CERCLA or similar state statutes, in the course of our ordinary operations.

Air. Our operations may be subject to the Clean Air Act and other federal and state statutes and regulations that impose certain pollution control requirements with respect to air emissions from operations, particularly in instances where a company constructs a new facility or modifies an existing facility. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe these requirements will have a material adverse affect on our operations.

Water. The Federal Water Pollution Control Act imposes strict controls against the unauthorized discharge of pollutants, including produced waters and other oil and natural gas wastes, into navigable waters. It provides for civil and criminal penalties for any unauthorized discharges of oil and other substances and, along with the Oil Pollution Act of 1990 (OPA), imposes substantial potential liability for the costs of oil or hazardous substance removal, remediation and damages. Similarly, the OPA imposes liability for the discharge of oil into or upon navigable waters or adjoining shorelines. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of an unauthorized discharge of pollutants into state waters.

Communication of Hazards. The Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and comparable state statutes require those entities that operate facilities for us to organize and disseminate information to employees, state and local organizations, and the public about the hazardous materials used in our operations and our emergency planning.

Employees

At December 31, 2005, there were approximately 2,600 persons directly involved in our management, administration and operations, approximately 2,365 of which are employees of EPCO that provide services to us under an administrative services agreement. The remaining 235 individuals primarily represent third-party contract personnel. For additional information regarding our relationship with EPCO, please read Item 13 of this annual report.

Significant Customers

Our revenues are derived from a wide customer base. During 2005, our largest customer, The Dow Chemical Company, accounted for 6.8% of our consolidated revenues. During 2004 and 2003, our largest customer, Shell Oil Company and affiliates (Shell), accounted for 6.5% and 5.5% of our consolidated revenues, respectively.

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

An investment in our units involves certain risks. If any of these risks were to occur, our business, results of operations, cash flows and financial condition could be materially adversely affected. In that case, the trading price of our units could decline, and you could lose part or all of your investment.

Among the key risk factors that may have a direct impact on our business, results of operations, cash flows and financial condition are:

Risks Inherent in an Investment in Us

Currently, our operating cash flow is derived primarily from cash distributions from Enterprise Products Partners.

Currently, our operating cash flow is primarily dependent upon Enterprise Products Partners making distributions to its partners. The amount of cash that Enterprise Products Partners can distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things, the:

- amount of hydrocarbons transported in its gathering and transmission pipelines;
- throughput volumes in its processing and treating operations;
- fees it charges and the margins it realizes for its services;
- price of natural gas;
- relationships among crude oil, natural gas and NGL prices;
- fluctuations in its working capital needs;
- level of its operating costs, including reimbursements to its general partner; and
- prevailing economic conditions.

In addition, the actual amount of cash Enterprise Products Partners will have available for distribution will depend on other factors, including:

- the level of sustaining capital expenditures it makes;
- the cost of any capital projects and acquisitions;
- its debt service requirements and restrictions contained in its obligations for borrowed money; and
- the amount of cash reserves established by Enterprise Products GP for the proper conduct of Enterprise Products Partners business.

Because of these factors, Enterprise Products Partners may not have sufficient available cash each quarter to continue paying distributions at its current level of $0.4375 per unit. Furthermore, the amount of cash that Enterprise Products Partners has available for distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. As a result, Enterprise Products Partners may be able to make cash distributions during periods when it records losses and may not be able to make cash distributions during periods when it records net income. Please read *Risks Related to Enterprise Products Partners Business* included within this Item 1A for a discussion of further risks affecting Enterprise Products Partners ability to generate distributable cash flow.

In the future, we may not have sufficient cash to pay distributions at our current distribution level or to increase distributions.

Because our primary source of operating cash flow currently consists of cash distributions from Enterprise Products Partners, the amount of distributions we are able to make to our unitholders may fluctuate based on the level of distributions Enterprise Products Partners makes to its partners. We cannot assure you that Enterprise Products Partners will continue to make quarterly distributions at its current level of $0.4375 per unit or increase its quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our unitholders if Enterprise Products Partners increases or decreases distributions to us, the timing and amount of such changes in distributions, if any, will not necessarily be comparable to the timing and amount of any changes in distributions made by Enterprise Products Partners to us. Factors such as capital contributions, debt service requirements, general, administrative and other expenses, reserves for future distributions and other cash reserves established by the board of directors of EPE Holdings may affect the distributions we make to our unitholders. Prior to making any distributions to our unitholders, we will reimburse EPE Holdings and its affiliates for all direct and indirect expenses incurred by them on our behalf. EPE Holdings has the sole discretion to determine the amount of these reimbursed expenses. The reimbursement of these expenses, in addition to the other factors listed above, could adversely affect the level of distributions we make to our unitholders. We cannot guarantee that in the future we will be able to pay distributions or that any distributions we do make will be at or above our current quarterly distribution of $0.28 per unit. The actual amount of cash that is available for distribution to our unitholders will depend on numerous factors, many of which are beyond our control or the control of EPE Holdings.

Restrictions in our credit facility could limit our ability to make distributions to our unitholders.

Our credit facility contains covenants limiting our ability to take certain actions. This credit facility also contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distribution to our unitholders if such distribution would cause an event of default or otherwise violate a covenant under this credit facility. For more information about our credit facility, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our unitholders do not elect our general partner or vote on our general partner s officers or directors. Affiliates of our general partner currently own a sufficient number of units to block any attempt to remove EPE Holdings.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Our unitholders do not have the ability to elect our general partner or the officers or directors of our general partner. Dan L. Duncan, through his control of Dan Duncan LLC, the sole member of EPE Holdings, controls our general partner and the election of all of the officers and directors of our general partner.

Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner or the officers or directors of our general partner. Our general partner may not be removed except upon the vote of the holders of at least 66 2/3% of our outstanding units. Because affiliates of EPE Holdings own more than one-third of our outstanding units, EPE Holdings currently cannot be removed without the consent of such affiliates. As a result, the price at which our units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue an unlimited number of limited partner interests without the consent of our unitholders, which will dilute your ownership interest in us and may increase the risk that we will not have sufficient available cash to maintain or increase our per unit distribution level.

Our partnership agreement provides that we may issue an unlimited number of limited partner interests without the consent of our unitholders. Such units may be issued on the terms and conditions established in the sole discretion of our general partner. Any issuance of additional units would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect market price of, units outstanding prior to such issuance. The payment of distributions on these additional units may increase the risk that we will be unable to maintain or increase our current quarterly distribution.

The market price of our units could be adversely affected by sales of substantial amounts of our units in the public markets, including sales by our existing unitholders.

Sales by any of our existing unitholders of a substantial number of our units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sale would be made in the public market or in a private placement, nor do we know what impact such potential or actual sales would have on our unit price in the future.

Risks arising in connection with the execution of our business strategy may adversely affect our ability to make or increase distributions and/or the market price of our units.

In addition to seeking to maximize distributions from Enterprise Products Partners, a principal focus of our business strategy includes acquiring general partner interests and associated incentive distribution rights and limited partner interests in publicly traded partnerships and, subject to our business opportunity agreements, acquiring assets and businesses that may or may not relate to Enterprise Products Partners business. However, we may not be able to grow through acquisitions if we are unable to identify attractive acquisition opportunities or acquire identified targets. In addition, increased competition for acquisition opportunities may increase our cost of making acquisitions or cause us to refrain from making acquisitions.

If we are able to make future acquisitions, we may not be successful in integrating our acquisitions into our existing or future assets and businesses. Risks related to our acquisition strategy include:

- the creation of conflicts of interests and competing fiduciary obligations that may inhibit our ability to grow or make additional acquisitions;
- additional or increased regulatory or compliance obligations, including financial reporting obligations;
- delays or unforeseen operational difficulties or diminished financial performance associated with the integration of new acquisitions, and the resulting delayed or diminished cash flows from such acquisitions;
- inefficiencies and complexities that may arise due to unfamiliarity with new assets, businesses or markets;
- conflicts with regard to the sharing of management responsibilities and allocation of time among overlapping officers, directors and other personnel;
- the inability to hire, train and retain qualified personnel to manage and operate our growing business; and

18

the inability to obtain required financing for our existing business and new investment opportunities.

To the extent we pursue an acquisition that causes us to incur unexpected costs, or that fails to generate expected returns, our results of operations, cash flows and financial condition may be adversely affected, and our ability to make distributions and/or the market price of our units may be negatively impacted.

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 in us to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of Dan Duncan LLC, as the sole member of EPE Holdings, to sell or transfer all or part of its ownership interest in EPE Holdings to a third party. The new owner of our general partner would then be in a position to replace the directors and officers of EPE Holdings.

All of our units and substantially all of the common units of Enterprise Products Partners that are owned by EPCO and its affiliates, other than Dan Duncan LLC and certian trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an affiliate of EPCO. Upon an event of default under this credit facility, a change in ownership or control of us or Enterprise Products Partners could result.

All of our units and substantially all of the common units of Enterprise Products Partners (other than the 13,454,498 common units we own) that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and certian trusts affiliated with Dan L. Duncan, are pledged as security under a credit facility of EPCO Holdings, Inc., a wholly owned subsidiary of EPCO. This credit facility contains customary and other events of default relating to certain defaults of the borrower, us, Enterprise Products Partners and other affiliates of EPCO. Upon an event of default, a change in control or ownership of us or Enterprise Products Partners could result.

All of our assets are pledged under our credit facility.

The 13,454,498 common units of Enterprise Products Partners and the 100% membership interest in Enterprise Products GP owned by us are pledged as security under our credit facility. Our credit facility contains customary and other events of default. Upon an event of default, the lenders under our credit facility could foreclose on our assets, which would have a material adverse effect on our business, financial condition and results of operations.

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

If at any time our general partner and its affiliates own more than 90% of our outstanding 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 units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units. At December 31, 2005, affiliates of EPE Holdings, including EPE Unit L.P. (the Employee Partnership), owned approximately 86.5% of our units.

We depend on the leadership and involvement of Dan L. Duncan and other key personnel for the success of our and our subsidiaries businesses.

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the Chairman of each of EPE Holdings and Enterprise Products GP. Mr. Duncan has been integral to the success of Enterprise Products Partners and EPCO due in part to his ability to identify and develop business opportunities, make strategic decisions and attract and retain key personnel. The loss of his leadership and involvement or the services of any members of our or Enterprise Products Partners senior management teams could have a material adverse effect on the business, results of operations, cash flows and financial condition of us, Enterprise Products Partners and our affiliates.

An increase in interest rates may cause the market price of our units to decline.

As interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our units to decline.

Enterprise Products Partners may issue additional units, which may increase the risk that Enterprise Products Partners will not have sufficient available cash to maintain or increase its per unit distribution level.

Enterprise Products Partners has wide latitude to issue additional units on terms and conditions established by Enterprise Products GP. The payment of distributions on those additional units may increase the risk that Enterprise Products Partners will be unable to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to distribute to our unitholders.

Unitholders liability as a limited partner may not be limited, and our unitholders may have to repay distributions or make additional contributions to us under certain circumstances.

As a limited partner in a partnership organized under Delaware law, our 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. EPE Holdings generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to EPE Holdings. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, neither we nor Enterprise Products Partners may make a distribution to our unitholders if the distribution would cause our or Enterprise Products Partners respective liabilities to exceed the fair value of our respective assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If in the future we cease to manage and control Enterprise Products Partners through our direct or indirect ownership of Enterprise Products GP, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control Enterprise Products Partners and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the Securities and Exchange Commission, or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates.

Our partnership agreement restricts the rights of unitholders owning 20% or more of our units.

Our unitholders voting rights are restricted by the provision in our partnership agreement generally providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than EPE Holdings and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders ability to influence the manner or direction of our management. As a result, the price at which our units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Risks Related to Conflicts of Interest

Conflicts of interest exist and may arise in the future among us, Enterprise Products Partners, TEPPCO Partners L.P. (TEPPCO), a publicly traded limited partnership the common units of which are listed on the NYSE under the ticker symbol TPP , and our respective general partners and affiliates. Future conflicts of interest may arise among us and the entities represented by any general partner interests we acquire or among Enterprise Products Partners, TEPPCO and such entities.

Conflicts of interest exist and may arise among us, Enterprise Products Partners, TEPPCO and our respective general partners and affiliates and entities affiliated with any general partner interests that we may acquire in the future.

Conflicts of interest exist and may arise in the future as a result of the relationships among us, Enterprise Products Partners, TEPPCO and our respective general partners and affiliates. EPE Holdings is controlled by Dan Duncan LLC, of which Dan L. Duncan is the sole member. Accordingly, Mr. Duncan has the ability to elect, remove and replace the directors and officers of EPE Holdings. Similarly, through his indirect control of the general partner of each of Enterprise Products Partners and TEPPCO, Mr. Duncan has the ability to elect, remove and replace the directors and officers of the general partner of each of Enterprise Products Partners and TEPPCO. The assets of Enterprise Products Partners and TEPPCO overlap in certain areas, which may result in various conflicts of interest in the future.

EPE Holdings directors and officers have fiduciary duties to manage our business in a manner beneficial to us and our partners. However, all of EPE Holdings executive officers and non-independent directors also serve as executive officers or directors of Enterprise Products GP and, as a result, have fiduciary duties to manage the business of Enterprise Products Partners in a manner beneficial to Enterprise Products Partners and its partners. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to Enterprise Products Partners, on the one hand, and us, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

Future conflicts of interest may arise among us and any entities whose general partner interests we or our affiliates acquire or among Enterprise Products Partners, TEPPCO and such entities. It is not possible to predict the nature or extent of these potential future conflicts of interest at this time, nor is it possible to determine how we will address and resolve any such future conflicts of interest. However, the resolution of these conflicts may not always be in our best interest or that of our unitholders.

If we are presented with certain business opportunities, Enterprise Products Partners will have the first right to pursue such opportunities.

Pursuant to an administrative services agreement, we have agreed to certain business opportunity arrangements to address potential conflicts that may arise among us, Enterprise Products Partners and the EPCO Group (which includes EPCO and its affiliates, excluding Enterprise Products GP, Enterprise Products Partners and its subsidiaries, us and EPE Holdings and TEPPCO, it s general partner and their controlled affiliates). If a business opportunity in respect of any assets other than equity securities, which we generally define to include general partner interests in publicly traded partnerships and similar interests and associated incentive distribution rights and limited partner interests or similar interests owned by the owner of such general partner or its affiliates, is presented to the EPCO Group, us, EPE Holdings, Enterprise Products GP or Enterprise Products Partners, then Enterprise Products Partners will have the first right to acquire such assets. The administrative services agreement provides, among other things, that Enterprise Products Partners will be presumed to desire to acquire the assets until such time as it advises the EPCO Group and us that it has abandoned the pursuit of such business opportunity, and we may not pursue the acquisition of such assets prior to that time. These business opportunity arrangements limit our ability to pursue acquisitions of assets that are not equity securities.

Our general partner s affiliates may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Except as provided in our partnership agreement and subject to certain business opportunity agreements, affiliates of our general partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

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

At December 31, 2005, Dan L. Duncan, EPCO and their controlled affiliates, including the Employee Partnership, owned approximately 86.5% of our units, and Dan Duncan LLC owned 100% of EPE Holdings. Dan Duncan serves as EPE Holdings Chairman as well as the Chairman of Enterprise Products GP. Conflicts of interest may arise among EPE Holdings and its affiliates, including TEPPCO, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, EPE Holdings may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following:

- EPE Holdings is allowed to take into account the interests of parties other than us, including EPCO, Enterprise Products GP, Enterprise Products Partners and their respective affiliates and any future general partners and limited partnerships acquired in the future in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing our units, unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;
- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to us;
- 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.

Our partnership agreement limits our general partner s fiduciary duties to us and our unitholders and restricts the remedies available to our 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 EPE Holdings to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles EPE Holdings 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;
- provides that our general partner is entitled to make other decisions in good faith if it reasonably believes that the decision is in our best interests;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the audit and 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 and that, in determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud, willful misconduct or gross negligence.

In order to become a limited partner of our partnership, our unitholders are required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Enterprise Products GP controls Enterprise Products Partners and may influence cash distributed to us.

Although we are the sole member of Enterprise Products GP, our control over Enterprise Products GP s actions is limited. The fiduciary duties owed by Enterprise Products GP to Enterprise Products Partners and its unitholders prevent us from influencing Enterprise Products GP to take any action that would benefit us to the detriment of Enterprise Products Partners or its unitholders. For example, Enterprise Products GP makes business determinations on behalf of Enterprise Products Partners that impact the amount of cash distributed by Enterprise Products Partners to its unitholders and to Enterprise Products GP, which in turn, affects the amount of cash distributions we receive from Enterprise Products Partners and Enterprise Partners GP and consequently, the amount of distributions we can pay to our unitholders.

Some of our directors and all of our executive officers face conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of EPCO, the general partner of Enterprise Products Partners, the general partner of TEPPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping executive officers and directors will allocate time among EPCO, us, Enterprise Products Partners, TEPPCO and other affiliates of EPCO. These officers and directors face conflicts regarding the allocation of their time, which may adversely affect our or Enterprise Products Partners business, results of operations and financial condition. Please read Item 10 of this annual report for more detailed information on which of our officers and directors serve as officers and/or directors of EPCO, the general partner of Enterprise Products Partners, the general partner of TEPPCO and other affiliates of EPCO.

Risks Related to Enterprise Products Partners' Business

Since our cash flows consist exclusively of distributions from Enterprise Products Partners, risks to Enterprise Products Partners business are also risks to us. We have set forth below risks to Enterprise Products Partners business, the occurrence of which could have negative impact on Enterprise Products Partners financial performance and decrease the amount of cash it is able to distribute to us, thereby impacting the amount of cash that we are able to distribute to our unitholders.

Changes in the prices of hydrocarbon products may materially adversely affect Enterprise Products Partners results of operations, cash flows and financial condition.

Enterprise Products Partners operates predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, its results of operations, cash flows and financial condition may be materially adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. Generally, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors that are impossible to control. These factors include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and NGLs; and
- conservation and the extent of governmental regulation of production and the overall economic environment.

Enterprise Products Partners is exposed to natural gas and NGL commodity price risk under certain of its natural gas processing and gathering and NGL fractionation contracts that provide for its fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which may materially adversely affect Enterprise Products Partners' results of operations, cash flows and financial position.

A decline in the volume of natural gas, NGLs and crude oil delivered to Enterprise Products Partners facilities could adversely affect its results of operations, cash flows and financial condition.

Enterprise Products Partners' profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at its facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by its facilities.

The crude oil, natural gas and NGLs available to Enterprise Products Partners' facilities will be derived from reserves produced from existing wells, which reserves naturally decline over time. To offset this natural decline, Enterprise Products Partners' facilities will need access to additional reserves. Additionally, some of its facilities will be dependent on reserves that are expected to be produced from newly discovered properties that are currently being developed.

Exploration and development of new oil and natural gas reserves is capital intensive, particularly offshore in the Gulf of Mexico. Many economic and business factors are beyond Enterprise Products Partners' control and can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. For example, a sustained decline in the price of natural gas and crude oil could result in a decrease in natural gas and crude oil exploration and development activities in the regions where Enterprise Products Partners' facilities are located. This could result in a decrease in volumes to its offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on its results of operations, cash flows and financial position. Additional reserves, if discovered, may not be developed in the near future or at all.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially

adversely affect Enterprise Products Partners' results of operations, cash flows and financial position.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could materially adversely affect Enterprise Products Partners' results of operations, cash flows and financial position. For example:

Ethane. If natural gas prices increase significantly in relation to ethane prices, it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that Enterprise Products Partners transports.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, its operating margin from selling isobutane could be reduced.

Propylene. A downturn in the domestic or international economy could cause reduced demand for propylene, which could cause a reduction in the volumes of propylene that Enterprise Products Partners produces and expose its investment in inventories of propane/propylene mix to pricing risk due to requirements for short-term price discounts in the spot or short-term propylene markets.

Enterprise Products Partners faces competition from third parties in its midstream businesses.

Even if reserves exist in the areas accessed by Enterprise Products Partners facilities and are ultimately produced, Enterprise Products Partners may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. Enterprise Products Partners competes with others, including producers of oil and natural gas, for any such production on the basis of many factors, including:

- geographic proximity to the production;
- costs of connection;

available capacity;

rates; and

access to markets.

Enterprise Products Partners future debt level may limit its future financial and operating flexibility.

As of December 31, 2005, Enterprise Products Partners had approximately $4.8 billion of consolidated debt outstanding. The amount of Enterprise Products Partners future debt could have significant effects on its operations, including, among other things:

a significant portion of Enterprise Products Partners' cash flow could be dedicated to the payment of principal and interest on its future debt and may not be available for other purposes, including the payment of distributions on its common units and capital expenditures;

credit rating agencies may view its debt level negatively;

covenants contained in its existing debt arrangements will require it to continue to meet financial tests that may adversely affect its flexibility in planning for and reacting to changes in its business;

its ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

it may be at a competitive disadvantage relative to similar companies that have less debt; and

it may be more vulnerable to adverse economic and industry conditions as a result of its significant debt level.

Enterprise Products Partners' public debt indentures currently do not limit the amount of future indebtedness that it can create, incur, assume or guarantee. Although its Multi-Year Revolving Credit Facility restricts its ability to incur additional debt above certain levels, any debt it may incur in compliance with these restrictions may still be substantial. For more information regarding Enterprise Products Partners Multi-Year Revolving Credit Facility, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Enterprise Products Partners' Multi-Year Revolving Credit Facility and each of its indentures for its public debt contain conventional financial covenants and other restrictions. For example, Enterprise Products Partners is prohibited from making distributions to its partners if such distributions would cause an even of default or otherwise violate a covenant under its Multi-Year Revolving Credit Facility. A breach of any of these restrictions by Enterprise Products Partners could permit its lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of its Multi-Year Revolving Credit Facility, to terminate all commitments to extend further credit. For additional information regarding Enterprise Products Partners' Multi-Year Revolving Credit Facility, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Enterprise Products Partners' ability to access capital markets to raise capital on favorable terms will be affected by its debt level, the amount of its debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade Enterprise Products Partners' credit rating, then Enterprise Products Partners could experience an increase in its borrowing costs, difficulty assessing capital markets or a reduction in the market price of its common units. Such a development could adversely affect Enterprise Products Partners' ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If Enterprise

Products Partners is unable to access the capital markets on favorable terms in the future, it might be forced to seek extensions for some of its short-term securities or to refinance some of its debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which Enterprise Products Partners might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that Enterprise Products Partners' leverage may adversely affect its future financial and operating flexibility and thereby impact its ability to pay cash distributions at expected rates.

Enterprise Products Partners may not be able to fully execute its growth strategy if it encounters illiquid capital markets or increased competition for investment opportunities.

Enterprise Products Partners' strategy contemplates growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance its ability to compete effectively and diversifying its asset portfolio, thereby providing more stable cash flow. Enterprise Products Partners regularly considers and enters into discussions regarding, and is currently contemplating and/or pursuing, potential joint ventures, stand alone projects or other transactions that it believes will present opportunities to realize synergies, expand its role in the energy infrastructure business and increase its market position.

Enterprise Products Partners will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on Enterprise Products Partners' access to capital will impair its ability to execute this strategy. If the cost of such capital becomes too expensive, Enterprise Products Partners' ability to develop or acquire accretive assets will be limited. Enterprise Products Partners may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence Enterprise Products Partners initial cost of equity include market conditions, fees it pays to underwriters and other offering costs, which include amounts it pays for legal and accounting services. The primary factors influencing Enterprise Products Partners cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges it pays to lenders.

In addition, Enterprise Products Partners is experiencing increased competition for the types of assets and businesses it has historically purchased or acquired. Increased competition for a limited pool of assets could result in Enterprise Products Partners losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit Enterprise Products Partners' ability to fully execute its growth strategy. Enterprise Products Partners' inability to execute its growth strategy may materially adversely affect its ability to maintain or pay higher distributions in the future.

Enterprise Products Partners growth strategy may adversely affect its results of operations if it does not successfully integrate the businesses that it acquires or if it substantially increases its indebtedness and contingent liabilities to make acquisitions.

Enterprise Products Partners growth strategy includes making accretive acquisitions. As a result, from time to time, Enterprise Products Partners will evaluate and acquire assets and businesses that it believes complement its existing operations. Enterprise Products Partners may be unable to integrate successfully businesses it acquires in the future. Enterprise Products Partners may incur substantial expenses or encounter delays or other problems in connection with its growth strategy that could negatively impact its results of operations, cash flows and financial condition. Moreover, acquisitions and business expansions involve numerous risks, including:

difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

establishing the internal controls and procedures that Enterprise Products Partners is required to maintain under the Sarbanes-Oxley Act of 2002;

- managing relationships with new joint venture partners with whom Enterprise Products Partners has not previously partnered;

- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, depletion and amortization expenses. As a result, Enterprise Products Partners capitalization and results of operations may change significantly following an acquisition. A substantial increase in Enterprise Products Partners indebtedness and contingent liabilities could have a material adverse effect on its results of operations, cash flows and financial condition. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

Enterprise Products Partners' growth strategy may adversely affect its results of operations if it does not successfully integrate the businesses that it acquires or if it substantially increases its indebtedness and contingent liabilities to make acquisitions.

Enterprise Products Partners' growth strategy includes making accretive acquisitions. As a result, from time to time, Enterprise Products Partners will evaluate and acquire assets and businesses that it believes complements its existing operations. Enterprise Products Partners may incur substantial expenses or encounter delays or other problems in connection with its growth strategy that could negatively impact its results of operations, cash flows and financial condition.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation and amortization expenses. As a result, Enterprise Products Partners' capitalization and results of operations may change significantly following an acquisition. A substantial increase in Enterprise Products Partners' indebtedness and contingent liabilities could have a material adverse effect on its results of operations, cash flows and financial condition.

Enterprise Products Partners' operating cash flows from our capital projects may not immediate.

Enterprise Products Partners is engaged in several construction projects involving existing and new facilities for which significant capital has been or will be expended, and Enterprise Products Partners' operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if Enterprise Products Partners builds a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time, and Enterprise Products Partners may not receive any material increase in operating cash flow from that project until a period of time after it is placed in service. If Enterprise Products Partners experiences any unanticipated or extended delays in generating operating cash flow from these projects, Enterprise Products Partners may be required to reduce or reprioritize its capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet its capital requirements.

Enterprise Products Partners actual construction, development and acquisition costs could exceed forecasted amounts.

Enterprise Products Partners will have significant expenditures for the development and construction of energy infrastructure assets, including some construction and development projects with significant technological challenges. Enterprise Products Partners may not be able to complete its projects at the costs estimated at the time of each project's initiation.

The interruption of distributions to Enterprise Products Partners from its subsidiaries and joint ventures may affect its ability to satisfy its obligations and to make distributions to its partners.

Enterprise Products Partners is a holding company with no business operations. Its only significant assets are the equity interests it owns in its subsidiaries and joint ventures. As a result, Enterprise Products Partners depends upon the earnings and cash flow of its subsidiaries and joint ventures and the distribution of that cash in order to meet its obligations and to allow it to make distributions to its partners.

In addition, the charter documents governing Enterprise Products Partners joint ventures typically vest in the joint venture management committee sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which Enterprise Products Partners participates have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture s ability to make distributions to Enterprise Products Partners under certain circumstances. Accordingly, Enterprise Products Partners joint ventures may be unable to make distributions to it at current levels, if at all.

Enterprise Products Partners may be unable to cause its joint ventures to take or not to take certain actions unless some or all of its joint venture participants agree.

Enterprise Products Partners participates in several joint ventures. Due to the nature of some of these arrangements, the participants have made substantial investments and, accordingly, have required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, Enterprise Products Partners may be unable to cause any of its joint ventures to take or not to take certain actions, even though those actions may be in the best interest of Enterprise Products Partners or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in Enterprise Products Partners being required to partner with different or additional parties.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail Enterprise Products Partners operations and otherwise materially adversely affect its cash flow and, accordingly, affect the market price of its common units.

Some of Enterprise Products Partners operations involve risks of personal injury, property damage and environmental damage, which could curtail its operations and otherwise materially adversely affect its cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. Enterprise Products Partners also operates oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. Virtually all of Enterprise Products Partners' operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes.

If one or more facilities that are owned by Enterprise Products Partners or that deliver oil, natural gas or other products to Enterprise Products Partners are damaged by severe weather or any other disaster, accident, catastrophe or event, Enterprise Products Partners' operations could be significantly interrupted.

Similar interruptions could result from damage to production or other facilities that supply Enterprise Products Partners facilities or other stoppages arising from factors beyond its control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that Enterprise Products Partners is a party to obligate Enterprise Products Partners to indemnify its customers for any damage or injury occurring during the period in which the customers natural gas is in its possession. Any event that interrupts the revenues generated by Enterprise Products Partners' operations, or which causes it to make significant expenditures not covered by insurance, could reduce its cash available for paying distributions and, accordingly, adversely affect the market price of its common units.

Enterprise Products Partners believes that EPCO maintains adequate insurance coverage on behalf of it, although insurance will not cover many types of interruptions that might occur. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of Enterprise Products Partners or procure other desirable insurance on commercially reasonable terms, if at all. If Enterprise Products Partners were to incur a significant liability for which it was not fully insured, a material adverse effect on its financial position and results of operations could occur. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

An impairment of goodwill and intangible assets could reduce Enterprise Products Partners earnings.

At December 31, 2005, Enterprise Products Partners balance sheet reflected $494 million of goodwill and $913.6 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States (GAAP) require Enterprise Products Partners to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If Enterprise Products Partners determines that any of its goodwill or intangible assets were impaired, it would be required to take an immediate charge to earnings with a correlative effect on partners equity and balance sheet leverage as measured by debt to total capitalization.

Increases in interest rates could materially adversely affect Enterprise Products Partners business, results of operations, cash flows and financial condition.

In addition to Enterprise Products Partners exposure to commodity prices, it has significant exposure to increases in interest rates. As of December 31, 2005, it had approximately $4.8 billion of consolidated debt, of which approximately $3.3 billion was at fixed interest rates and approximately $1.5 billion was at variable interest rates, after giving effect to existing interest swap arrangements. From time to time, Enterprise Products Partners may enter into additional interest rate swap arrangements, which could increase its exposure to variable interest rates. As a result, its results of operations, cash flows and financial condition, could be materially adversely affected by significant increases in interest rates.

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

The use of derivative financial instruments could result in material financial losses by Enterprise Products

Partners.

Enterprise Products Partners historically has sought to limit a portion of the adverse effects resulting from changes in oil and natural gas commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that Enterprise Products Partners hedges its commodity price and interest rate exposures, it will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in its favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed.

Enterprise Products Partners pipeline integrity program may impose significant costs and liabilities on it.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as high consequence areas. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, Enterprise Products Partners cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. Enterprise Products Partners will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause Enterprise Products Partners to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Environmental costs and liabilities and changing environmental regulation could materially affect Enterprise

Products Partners results of operations, cash flows and financial condition.

Enterprise Products Partners operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Third parties may also have the right to pursue legal actions to enforce compliance.

Enterprise Products Partners will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of Enterprise Products Partners' operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Federal, state or local regulatory measures could materially adversely affect Enterprise Products Partners

business, results of operations, cash flows and financial condition.

The FERC regulates Enterprise Products Partners' interstate natural gas pipelines and interstate natural gas storage facilities under the Natural Gas Act, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates Enterprise Products Partners interstate propylene pipelines. State regulatory agencies regulate its intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the Natural Gas Act, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for the services, terms and condition of service and certification and construction of new facilities. The FERC requires that Enterprise Products Partners' services are provided on a non-discriminatory basis so that all shippers have open access to its pipelines and storage. Pursuant to the FERC s jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC Staff and proposed rate increases may be challenged by protest.

Enterprise Products Partners has interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Department of Interior, under the Outer Continental Shelf Lands Act, and by the Department of Transportation's Office of Pipeline Safety under the Natural Gas Pipeline Safety Act.

Enterprise Products Partners' intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and its intrastate natural gas pipelines are subject to regulation by the FERC pursuant to Section 311 of the Natural Gas Policy Act. Enterprise Products Partners also has natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

For a general overview of federal, state and local regulation applicable to Enterprise Products Partners' assets, please read the regulation and environmental information included under Item 1 of this annual report. This regulatory oversight can affect certain aspects of Enterprise Products Partners' business and the market for its products and could materially adversely affect its cash flows.

Terrorist attacks aimed at Enterprise Products Partners facilities could adversely affect its business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on Enterprise Products Partners facilities or pipelines or those of its customers could have a material adverse effect on its business.

Tax Risks to Our Unitholders

If we or Enterprise Products Partners were to become subject to entity level taxation for federal or state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax benefit of an investment in our 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 (Internal Revenue Service) on this matter. The value of our investment in Enterprise Products Partners depends largely on Enterprise Products Partners being treated as a partnership for federal income tax purposes.

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

If Enterprise Products Partners were treated as a corporation for federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate. Distributions to us would generally be taxed again as corporate distributions, and no income, gains, losses, deduction or credits would flow through to us. As a result, there would be a material reduction in our anticipated cash flow, likely causing a substantial reduction in the value of our units.

Current law may change, causing us or Enterprise Products Partners to be treated as a corporation for federal income tax purposes or otherwise subjecting us or Enterprise Products Partners 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 or Enterprise Products Partners as an entity, the cash available for distribution to our unitholders would be reduced.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely impacted, and the costs of any contest will be borne by our unitholders and EPE Holdings.

The IRS may adopt positions that differ from the position we take, even positions taken with advice of counsel. 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 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 for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

A successful IRS contest of the federal income tax positions taken by Enterprise Products Partners may adversely impact the market for its common units, and the costs of any contest will be borne by Enterprise Products Partners, and therefore indirectly by us and the other unitholders of Enterprise Products Partners.

The IRS may adopt positions that differ from the positions Enterprise Products Partners takes, even positions taken with the advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions Enterprise Products Partners takes. A court may not agree with all of the positions Enterprise Products Partners takes. Any contest with the IRS may materially and adversely impact the market for Enterprise Products Partners common units and the prices at which the common units trade. In addition, the costs of any contest with the IRS will be borne by Enterprise Products Partners and therefore indirectly by us, as a unitholder and as the owner of the general partner of Enterprise Products Partners, and by the other unitholders of Enterprise Products Partners.

Even if our unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Our unitholders will be 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. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

Tax gain or loss on the disposition of our units could be different than expected.

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

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

Investment in 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. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships (including us) as qualifying income to a regulated investment company. 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 our 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 our units.

Because we cannot match transferors and transferees of units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of units and could have a negative impact on the value of our units or result in audit adjustments to our unitholders tax returns.

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

In addition to federal income taxes, our 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 or Enterprise Products Partners do business or own property. Our 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, our unitholders may be subject to penalties for failure to comply with those requirements. We or Enterprise Products Partners may own property or conduct business in other states or foreign countries in the future. It is our unitholders responsibility to file all federal, state and local tax returns.

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

None.

Item 2. ***Properties.***

The following sections provide information regarding our principal plants, pipelines and other assets by segment. For information regarding our significant historical throughput, production and processing rates, please read Item 7 of this annual report.

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which our interests and those of our unconsolidated affiliates are derived 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 our significant 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 title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our unconsolidated affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

NGL Pipelines & Services

The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 1, 2006.

Description of Asset	**Location(s)**	**Our Ownership Interest**	**Length (Miles)**	**Useable Storage Capacity (MMBbls)**
NGL pipelines: (1)				
Mid-America Pipeline System	Midwest and Western U.S. (2)	100%	7,226	
Dixie Pipeline	South and Southeastern U.S.	65.9% (3)	1,301	
Seminole Pipeline	Texas	90% (4)	1,281	
Texas NGL System (5)	Texas	100%	1,039	
Louisiana Pipeline System	Louisiana	Various (6)	655	
Promix NGL Gathering System	Louisiana	50% (7)	410	
Houston Ship Channel	Texas	100%	266	
Lou-Tex NGL	Texas, Louisiana	100%	204	
Others (5 systems) (8)	Alabama, Louisiana, Mississippi	Various	427	
Total miles			12,809	
NGL and related product storage facilities by state:				
Texas				114.9
Louisiana				13.0
Mississippi				10.9
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, Oklahoma, Utah)				9.6
Total capacity (9)				148.4

(1) The maximum number of barrels that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of the systems. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacities of the systems cannot be stated. We measure the utilization rates of our NGL pipelines in terms of throughput (on a net basis in accordance with our ownership interest). Total net volumes for our NGL pipelines during 2005, 2004 and 2003 were 1,360 MBPD, 1,343 MBPD and 1,196 MBPD, respectively.

(2) This system crosses thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin.

(3) We hold a 65.9% interest in this system through a majority owned subsidiary, Dixie Pipeline Company (Dixie).

(4) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company (Seminole).

(5) Acquired in connection with the GulfTerra Merger in September 2004.

(6) Of the 655 total miles for this system, we own 100% of 559 miles; 44.3% of 53 miles; and 32.2% of the remaining 43 miles.

(7) Our ownership interest in this pipeline is held indirectly through our equity method investment in K/D/S Promix LLC (Promix).

(8) Includes our Tri-States, Belle Rose, Wilprise and Chunchula pipelines located in the coastal regions of Alabama, Louisiana and Mississippi and a pipeline held by Venice Energy Services Company, LLC (VESCO), an equity investment of ours.

(9) The 148.4 MMBbls of total useable storage capacity includes 21.3 MMBbls held under operating leases.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of Tri-States and a small portion of the Louisiana Pipeline System.

The *Mid-America Pipeline System* is a regulated NGL pipeline system consisting of three primary segments: the 2,548-mile Rocky Mountain pipeline, the 2,740-mile Conway North pipeline and the 1,938-mile Conway South pipeline. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada s Western Sedimentary Basin through third-party connections. The Conway South pipeline connects the Conway hub with Kansas refineries and transports NGLs from Conway, Kansas to the Hobbs hub (with interconnections with our Seminole pipeline at the Hobbs hub). We also own fifteen unregulated propane terminals that are an integral part of the Mid-America Pipeline System.

Approximately 60% of the volumes transported on the Mid-America system are mixed NGLs originating from natural gas processing plants located in the Permian Basin in West Texas, the Hugoton Basin of southwestern Kansas, the San Juan Basin of northwest New Mexico, and the Green River Basin of southwestern Wyoming. The remaining volumes are generally purity NGL products originating from NGL fractionators in the mid-continent areas of Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

The *Dixie Pipeline* is a regulated propane pipeline extending from southeast Texas and Louisiana to markets in the southeastern United States. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi.

The *Seminole Pipeline* is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area to southeastern Texas. The primary source of throughput for the Seminole pipeline is the Mid-America Pipeline System.

The *Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system includes 379 miles of pipeline used to gather and transport mixed NGLs from our South Texas natural gas processing facilities to our South Texas NGL fractionation facilities. The pipeline system also includes approximately 660 miles of pipelines that deliver NGLs from our South Texas fractionation facilities to refineries and petrochemical plants located from Corpus Christi to Houston and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

The *Louisiana Pipeline System* is a network of nine NGL pipelines located in Louisiana. This system transports NGLs originating in southern Louisiana and Texas to refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other facilities located in Louisiana.

The *Promix NGL Gathering System* is a NGL pipeline system that gathers mixed NGLs from natural gas processing plants in Louisiana for delivery to the Promix NGL fractionator. This gathering system is an integral part of the Promix NGL fractionation facility.

The *Houston Ship Channel* pipeline system is a collection of pipelines extending from our Houston Ship Channel import/export facility and Morgan s Point facility to Mont Belvieu, Texas. This system is used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities.

The *Lou-Tex NGL* pipeline system is used to provide transportation services for NGLs and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from certain of our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility.

Our NGL and related product storage facilities are integral parts of our pipeline and other operations. In general, these underground storage facilities are used to store our and our customers NGLs and petrochemicals. Our underground storage facilities include locations in Arizona, Kansas and Utah that were acquired in July 2005 from Ferrellgas L.P. We operate these facilities, with the exception of certain storage locations operated for us by a third party in Louisiana and Mississippi.

The following table summarizes the significant natural gas processing and NGL fractionation assets of our NGL Pipelines & Services business segment at February 1, 2006.

Description of Asset	**Location(s)**	**Our Ownership Interest**	**Net Gas Processing Capacity (Bcf/d)** [2]	**Total Gas Processing Capacity (Bcf/d)**	**Net Plant Capacity (MBPD)**	**Total Plant Capacity (MBPD)**
Natural gas processing facilities: [1, 3,4]						
Toca	Louisiana	60.3%	0.66	1.10		
Chaco [4]	New Mexico	100%	0.65	0.65		
North Terrebonne	Louisiana	44.3%	0.58	1.30		
Yscloskey	Louisiana	31.1%	0.54	1.85		
Calumet	Louisiana	31.5%	0.50	1.60		
Neptune	Louisiana	66%	0.43	0.65		
Pascagoula	Mississippi	40%	0.40	1.50		
Thompsonville [4]	Texas	100%	0.30	0.30		
Shoup [4]	Texas	100%	0.29	0.29		
Gilmore [4]	Texas	100%	0.26	0.26		
Armstrong [4]	Texas	100%	0.25	0.25		
Matagorda [4]	Texas	100%	0.25	0.25		
Others (12 facilities) [4,5]	Texas, New Mexico, Louisiana	Various [6]	1.24	5.38		
Total processing capacities			6.35	15.38		
NGL fractionation facilities: [7,8]						
Mont Belvieu	Texas	75%			158	210
Norco	Louisiana	100%			75	75
Promix	Louisiana	50%			73	145
Shoup	Texas	100%			69	69
BRF	Louisiana	32.2%			19	60
Others (4 facilities) [9]	Texas, Louisiana	Various			45	93
Total plant capacities					439	652

(1) We own direct consolidated interests in all of our natural gas processing facilities with the exception of our 13.1% interest in a facility held through our equity method investment in VESCO.

(2) The approximate net natural gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

(3) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 53%, 61% and 63% during 2005, 2004 and 2003, respectively.

(4) As a result of the GulfTerra Merger, we acquired ownership interest in eleven natural gas processing facilities having net gas processing capacity of 2.66 Bcf/d and gross gas processing capacity of 2.8 Bcf/d.

(5) Includes our Venice, Blue Water, Sea Robin, Patterson II, Iowa and Burns Point facilities located in Louisiana; Indian Basin facility located in New Mexico; and San Martin, Delmita, Shilling, Sonora and Indian Springs facilities located in Texas. We acquired the Indian Springs facility in January 2005.

(6) Our ownership in these facilities ranges from 1.9% to 100%.

(7) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 70% during each of the years 2005, 2004 and 2003.

(8) We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50% interest in a facility held through our equity method investment in Promix; a 32.2% interest in a facility owned by Baton Rouge Fractionators LLC (BRF); and a 13.1% interest in a facility owned by VESCO.

(9) Includes our Tebone and VESCO NGL facilities located in Louisiana and our Armstrong and Delmita facilities located in Texas.

At the core of our natural gas processing business are twenty-four processing plants located in Texas, Louisiana, Mississippi and New Mexico. Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas in connection with gathering pipelines. We operate the Toca, Chaco, North Terrebonne, Calumet and Neptune plants and all of the Texas facilities.

Our NGL marketing activities utilize a fleet of approximately 600 railcars, the majority of which are leased. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States. We have rail loading and unloading facilities in Arizona, Kansas, Louisiana, Mississippi and Texas. These facilities service both our rail shipments and those of our customers.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities, with the exception of the facility owned by VESCO.

Our *Mont Belvieu* NGL fractionation facility is located at Mont Belvieu, Texas, which is a key hub of the domestic and international NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountain Overthrust, East Texas and the Gulf Coast.

The *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants, including our Yscloskey and Toca natural gas processing plants.

The *Promix* NGL fractionation facility receives mixed NGLs from natural gas processing plants on the Mississippi and Alabama Gulf Coast through a connection with our Belle Rose and Tri-States NGL pipelines. In addition to the 410-mile Promix NGL pipeline, Promix owns five NGL storage caverns and a barge loading facility that are integral to its operations.

Our *Shoup* NGL fractionation facility fractionates mixed NGLs supplied by our South Texas natural gas processing facilities.

The *BRF* facility processes mixed NGLs from production fields in Alabama, Mississippi and southern Louisiana as well as offshore Gulf of Mexico areas.

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We lease an import facility that can offload NGLs from tanker vessels at a rate of 10,000 barrels per hour. In addition, we own an export facility that can load cargoes of refrigerated propane and butane onto tanker vessels at rates of up to 5,000 barrels per hour. In addition, we own a barge dock that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. Our average combined NGL import and export volumes were 119 MBPD, 91 MBPD and 79 MBPD for 2005, 2004 and 2003, respectively.

Onshore Natural Gas Pipelines & Services

The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 1, 2006.

Description of Asset	**Location(s)**	**Our Ownership Interest**	**Length (Miles)**	**Approximate Capacity, Natural Gas (MMcf/d)**	**Gross Capacity (Bcf)**
Onshore natural gas pipelines: (1)					
Texas Intrastate System (2)	Texas	100% (3)	8,222	4,975	
San Juan Gathering System (2)	New Mexico, Colorado	100%	5,404	1,100	
Permian Basin System (2)	Texas, New Mexico	100%	1,477	490	
Acadian Gas System	Louisiana	100% (4)	1,027	954	
Alabama Intrastate System (2)	Alabama	100%	402	200	
Other (4 systems) (5)	Texas, Mississippi	Various (6)	684		
Total miles			17,216		
Natural gas storage facilities:					
Petal (2)	Mississippi	100%			11.9
Hattiesburg (2)	Mississippi	100%			4.0
Wilson (2)	Texas	Leased (7)			6.4
Acadian	Louisiana	Leased (8)			3.0
Total gross capacity					25.3

(1) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 73%, 75% and 63% during 2005, 2004 and 2003, respectively.

(2) Acquired in connection with the GulfTerra Merger in September 2004.

(3) We own a 50% undivided interest in the 733-mile Channel pipeline system, which is a component of the Texas Intrastate System.

(4) We own 100% of 1,000 miles of the Acadian Gas System and 49.5% of the related 27-mile Evangeline natural gas pipeline.

(5) Includes the Delmita, Big Thicket and Indian Springs gathering systems located in Texas and the Petal pipeline located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. We acquired the Indian Springs gathering system in January 2005.

(6) We own 100% of these assets with the exception the Indian Springs system, in which we indirectly own an 80% equity interest in this system through a majority owned subsidiary.

(7) Facility held under an operating lease that expires in January 2008 which contains certain renewal options.

(8) Facility held under an operating lease that expires in December 2012.

The following information highlights the general use of each of our principal onshore natural gas pipelines and storage facilities, all of which we operate.

The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial consumers. This system serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area, and the Houston Ship Channel industrial market. The Texas Intrastate System is comprised of the 7,292-mile GulfTerra Texas Intrastate pipeline system, the 197-mile TPC Offshore gathering system and the 733-mile Channel pipeline system. The Wilson natural gas storage facility is an integral part of the Texas Intrastate System.

The *San Juan Gathering System* serves natural gas producers in the San Juan Basin of New Mexico and Colorado. This system gathers natural gas production from over 10,450 wells in the San Juan Basin and delivers the natural gas to natural gas processing facilities, including our Chaco facility.

The *Permian Basin System* gathers natural gas from wells in the Permian Basin region of Texas and New Mexico and delivers natural gas into the El Paso Natural Gas, Transwestern and Oasis pipelines. The Permian Basin System is comprised of the 674-mile Waha system and 803-mile Carlsbad system.

The *Acadian Gas System* purchases, transports, stores and sells natural gas in Louisiana. The Acadian Gas System is comprised of the 577-mile Cypress pipeline, 423-mile Acadian pipeline and the 27-mile Evangeline pipeline. The Acadian natural gas storage facility is an integral part of the Acadian Gas System.

The *Alabama Intrastate System* gathers coal bed methane from wells in the Black Warrior Basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

Our *Petal* and *Hattiesburg* underground storage facilities are strategically situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets and are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems.

Offshore Pipelines & Services

The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 1, 2006, all of which are located in the Gulf of Mexico primarily offshore Louisiana and Texas.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines: (1)					
Manta Ray Offshore Gathering System	25.7% (2)	250		206	
High Island Offshore System (3)	100%	204		1,800	
Viosca Knoll Gathering System (3)	100%	162		1,000	
Green Canyon Laterals (3)	Various (4)	136		649	
Anaconda Gathering System (3)	100%	136		550	
Nautilus System	25.7% (2)	101		154	
East Breaks System (3)	100%	85		400	
Phoenix Gathering System (3)	100%	78		450	
Nemo Gathering System	33.9% (5)	24		102	
Falcon Gas Pipeline (3)	100%	14		400	
Total miles		1,190			
Offshore crude oil pipelines: (6)					
Cameron Highway Oil Pipeline (3)	50%(7)	378			250
Poseidon Oil Pipeline System (3)	36%(8)	324			144
Constitution Oil Pipeline	100%	70			80
Allegheny Oil Pipeline (3)	100%	43			140
Marco Polo Oil Pipeline (3)	100%	36			120
Typhoon Oil Pipeline (3)	100%	16			80
Tarantula Oil Pipeline (3)	100%	4			30
Total miles		871			
Offshore platforms: (3,9)					
Ship Shoal 332A (10)	62%		438		
Ship Shoal 332B (10)	50% (7)		438		
Marco Polo	50% (11)		4,300	150	60
Viosca Knoll 817	100%		671	140	5
Garden Banks 72	50%		518	40	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 30%, 32% and 41% during 2005, 2004 and 2003, respectively.

(2) Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune Pipeline Company, LLC.

(3) Acquired in connection with the GulfTerra Merger in September 2004. Data shown for the Anaconda Gathering System includes our recently completed 30-mile Constitution Gas Pipeline, which has a net capacity of approximately 200 MMcf/d.

(4) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100%.

(5) Our ownership interest in this pipeline is held indirectly through our equity method investment in Nemo Gathering Company, LLC.

(6) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 17% and 27% during 2005 and 2004, respectively.

(7) Our ownership interest in this asset is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company (Cameron Highway).

(8) Our ownership interest in this asset is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC.

(9) On a weighted-average basis, utilization rates during 2005 and 2004 for these assets (based on the periods that we held an ownership interest) were approximately 26% and 32% in connection with natural gas capacity and approximately 9% and 14% for crude oil capacity, respectively.

(10) These platforms serve as pipeline junctions; therefore, we do not have processing capacities to report for these assets.

(11) Our ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines. We operate our offshore natural gas pipelines, with the exception of the Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals.

The *Manta Ray Offshore Gathering System* transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System.

The *High Island Offshore System*, (HIOS) transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System.

The *Viosca Knoll Gathering System* transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

The *Green Canyon Laterals* consist of 28 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including the HIOS.

The *Anaconda Gathering System* connects our Marco Polo platform and Constitution Gas Pipeline to the ANR pipeline system. The Anaconda Gathering System includes our wholly-owned Constitution Gas Pipeline, which was completed in late 2005 and serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. We initiated flows into our Constitution Gas Pipeline during the first quarter of 2006.

The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant.

The *East Breaks System* connects the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25 to the HIOS.

The *Phoenix Gathering System* connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

The *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

The *Falcon Gas Pipeline* delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located on the Brazos Addition Block 133 platform.

The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate.

The *Cameron Highway Oil Pipeline*, which commenced operations during the first quarter of 2005, gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas.

The *Poseidon Oil Pipeline System* gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana.

The *Constitution Oil Pipeline* was completed in late 2005 and serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. Initial throughput volumes were received during the first quarter of 2006. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

The *Allegheny Oil Pipeline* connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

The *Marco Polo Oil Pipeline* gathers crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

The following information highlights the general use of each of our principal Gulf of Mexico offshore platforms. We operate these offshore platforms with the exception of the Marco Polo platform and East Cameron 373.

The *Ship Shoal 332A* platform is a junction platform, which serves as a location for crude oil and natural gas to enter our system of assets. Crude oil and natural gas produced in the deepwater Gulf of Mexico is transported to the Ship Shoal 332A platform via several third-party pipelines. Crude oil enters our Poseidon Oil Pipeline System and Allegheny Oil Pipelines at the Ship Shoal 332 A platform, and natural gas enters our Manta Ray Offshore Gathering System.

The *Ship Shoal 332B* platform is a junction platform for crude oil pipelines. Crude oil produced in the deepwater Gulf of Mexico is transported to the Ship Shoal 332B platform on our Poseidon Oil Pipeline System and Constitution Oil Pipeline and third-party pipelines. The crude oil is then shipped off this platform via our Cameron Highway Oil Pipeline.

The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2 and K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

The *Viosca Knoll 817* platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.

The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

The *East Cameron 373* platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.

The *Falcon Nest* currently platform processes natural gas from the Falcon field.

Petrochemical Services

The following table summarizes the significant assets of our Petrochemical Services segment at February 1, 2006.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities: (1)					
Mont Belvieu (3 plants)	Texas	Various (2)	58	72	
BRPC	Louisiana	30% (3)	7	23	
Total capacity			65	95	
Isomerization facility:					
Mont Belvieu (4)	Texas	100%	116	116	
Petrochemical pipelines: (5)					
Lou-Tex Propylene	Texas, Louisiana	100%			291
Lake Charles	Texas, Louisiana	50% (6)			88
Others (7 systems) (7)	Texas, Louisiana	Various (8)			311
Total miles					690
Octane additive production facilities:					
Mont Belvieu	Texas	100%	*(Dual Use)* (9)		

(1) On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest) were approximately 83%, 86% and 88% during 2005, 2004 and 2003, respectively.

(2) We own a 54.6% interest and lease the remaining 45.4% of a facility having 17 MBPD of plant capacity. We own a 66.7% interest in a second facility having 41 MBPD of total plant capacity. We own 100% of the remaining facility, which has 14 MBPD of plant capacity.

(3) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator, LLC (BRPC).

(4) On a weighted-average basis, utilization rates for this facility were approximately 70% for 2005 and 66% for each of 2004 and 2003.

(5) The maximum number of barrels that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of the systems. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacities of the systems cannot be stated. We measure the utilization rates of our petrochemical pipelines in terms of throughput (on a net basis in accordance with our ownership inte rest). Total net volumes for our petrochemical pipelines during 2005, 2004 and 2003 were 64 MBPD, 71 MBPD and 68 MBPD, respectively.

(6) Of the 88 total miles for this pipeline, we own 50% of 82 miles and 100% of the remainder.

(7) Includes our Port Neches, Bay Area, Texas City, La Porte, Morgan s Point and other petrochemical pipelines located in Texas and our Sabine Propylene pipeline located in Texas and Louisiana.

(8) We own 100% of these pipelines with the exception of (i) the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company, L.P. and La Porte GP, LLC and (ii) the 16-mile Bay Area pipeline, in which we own an undivided 66% interest.

(9) This facility is capable of producing either isooctane or MTBE as conditions warrant. At full capacity, the facility can produce approximately 12 MBPD of isooctane or 15.5 MBPD of MTBE. On a weighted-average basis, utilization rates for these assets (based on the periods that we held an ownership interest and the products produced) were approximately 29%, 83% and 62% during 2005, 2004 and 2003, respectively. The facility was capable of producing only MTBE prior to mid-2005.

We produce polymer grade propylene at our Mont Belvieu facilities and chemical grade propylene at our BRPC facility. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of ExxonMobil Corporation into chemical grade propylene. The production of polymer grade propylene from our Mont Belvieu plants is primarily used in our petrochemical marketing activities.

The Lou-Tex Propylene pipeline is used to transport propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Currently, this pipeline is used to transport chemical grade propylene. This business segment also includes an above-ground polymer grade propylene storage and export facility located in Seabrook, Texas. This facility can load vessels at rates up to 5,000 barrels per hour. We operate all of the assets in our Petrochemical Services business segment.

Item 3. ***Legal Proceedings.***

On occasion, we are named as a defendant in litigation relating to our normal business operations, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activity. We are not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns the facility. It is possible, however, that MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits. In connection with our purchase of additional equity interests in the owner of the octane-additive production facility in 2003 from an affiliate of Devon Energy Corporation (Devon) and in 2004 from an affiliate of Sunoco, Inc. (Sun), Devon and Sun indemnified us for any related liability (including liabilities described above) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in the facility.

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

None.

PART II

Item 5. ***Market for Registrant s Common Equity, Related Unitholder Matters and***

Issuer Purchases of Equity Securities.

Market Information and Cash Distributions

Our units are listed on the NYSE under the ticker symbol EPE. As of February 15, 2006, there were an estimated 19 unitholders of record of our units. The following table presents the high and low sales prices of our units (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid with respect to our units. The following information pertains to the period since our initial public offering in August 2005.

	Price Ranges		**Cash Distribution History**		
			Per	**Record**	**Payment**
	High	**Low**	**Unit**	**Date**	**Date**
2005					
3rd Quarter	$35.310	$31.650	$0.092	Oct. 31, 2005	Nov. 10, 2005
4th Quarter	$38.790	$33.160	$0.2800	Jan. 31, 2006	Feb. 10, 2006

On November 10, 2005, we paid a prorated quarterly distribution of $0.092 per unit. The prorated distribution applied to the 32-day period beginning on August 30, 2005 (the day after we completed our initial public offering) to September 30, 2005 and was based on a declared initial quarterly distribution rate of $0.265 per unit.

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our unitholders) occur within 50 days after the end of such quarter. We expect to fund our quarterly cash distributions to our unitholders primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, please read *Liquidity and Capital Resources* included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities by us during 2005.

In connection with the contribution of net assets by affiliates of EPCO to Enterprise GP Holdings L.P. in August 2005, affiliates of EPCO received 74,667,332 units of Enterprise GP Holdings L.P.

Units Authorized for Issuance Under Equity Compensation Plan

Please read the information included under Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

We did not repurchase any of our units during 2005.

Item 6. ***Selected Financial Data.***

The following table presents selected historical financial data of Enterprise GP Holdings L.P. The operating results for 2005, 2004 and 2003 and balance sheet information at December 31, 2005 and 2004 are derived from our audited financial statements and should be read in conjunction with such audited financial statements included under Item 8 of this annual report. The operating results and balance sheet information for periods prior to 2005 are derived from the unaudited financial information of our predecessor, Enterprise Products GP and subsidiaries, which includes Enterprise Products Partners. In addition, information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts (except per unit data) are in thousands.

	Year Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Operating results data: [1]					
Revenues	$ 12,256,959	$ 8,321,202	$ 5,346,431	$ 3,584,783	$ 2,641,913
Income from continuing operations [2]	$ 55,503	$ 29,562	$ 15,861	$ 7,351	$ 5,460
Income per unit from continuing operations:					
Basic [3]	$ 0.70	$ 0.40	$ 0.21	$ 0.10	$ 0.07
Diluted [3]	$ 0.70	$ 0.40	$ 0.21	$ 0.10	$ 0.07
Other financial data:					
Distributions per unit [4]	$ 0.372	n/a	n/a	n/a	n/a
Commodity hedging income (loss) [5]	$ 1,095	$ 448	$ (619)	$ (51,344)	$ 101,290
	As of December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Financial position data: [1]					
Total assets	$ 12,588,188	$ 11,315,901	$ 4,802,802	$ 4,235,494	$ 2,428,540
Long-term and current maturities of debt [6]	$ 4,968,280	$ 4,647,669	$ 2,139,548	$ 2,246,463	$ 855,278
Partners' equity [7]	$ 715,306	$ 74,038	$ 36,443	$ 16,987	$ 18,677
Total units outstanding	88,884	74,667	74,667	74,667	74,667

(1) In general, our historical operating results and financial position have been affected by numerous acquisitions since 2001. Our most significant transaction to date was the GulfTerra Merger, which was completed on September 30, 2004. The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The GulfTerra Merger and our other acquisitions were accounted for using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective purchase dates. For additional information regarding such transactions, please read Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Amounts presented for 2005 and 2004 are prior to the cumulative effect of accounting changes.

(3) The denominator used to calculate basic and diluted per unit amounts for all periods includes the 74,667,332 sponsor units issued to affiliates of EPCO in connection with their contribution of net assets to the parent company in August 2005.

(4) On November 10, 2005, we paid a prorated quarterly distribution of $0.092 per unit with respect to the third quarter of 2005. In January 2006, we declared a quarterly cash distribution of $0.28 per unit with respect to the fourth quarter of 2005, which was paid on February 10, 2006.

(5) Income from continuing operations includes our gain or loss from commodity hedging activities. A variety of factors influence whether or not a particular hedging strategy is successful. As a result of incurring significant losses from commodity hedging transactions in early 2002 due to a rapid increase in natural gas prices, we exited those commodity hedging strategies that created the losses. Since that time, we have utilized only a limited number of commodity financial instruments. For additional information regarding our use of financial instruments, please read Item 7A of this annual report.

(6) In general, the balances of our long-term and current maturities of debt have increased over time as a result of financing all or a portion of acquisitions and growth capital spending.

(7) Affiliates of EPCO contributed certain ownership interests in Enterprise Products Partners to us in August 2005. The contributed assets were recorded by the parent company at their net historical carrying amount of $160.6 million. Net proceeds from the sale of units in our initial public offering were approximately $373 million. For additional information, please see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

For the years ended December 31, 2005, 2004 and 2003.

We own all of the member interests of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., and 13,454,498 common units of Enterprise Products Partners L.P. We were formed in April 2005 and completed our initial public offering of 14,216,784 units in August 2005.

Significant Relationships referenced in this Management s Discussion and

Analysis of Financial Condition and Results of Operations

Unless the context requires otherwise, references to *we*, *us*, *our* or *Enterprise GP Holdings L.P.* are intended to mean and include the business and operations of Enterprise GP Holdings L.P., the parent company, as well as its consolidated subsidiaries, which include Enterprise Products GP, LLC and Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to *the parent company* are intended to mean and include Enterprise GP Holdings L.P., individually as the parent company, and not on a consolidated basis.

References to *EPE Holdings* mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings L.P.

References to *Enterprise Products Partners* mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to *Enterprise Products GP* mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners L.P.

References to *EPCO* mean EPCO, Inc., which is a related party affiliate to all of the foregoing named entities.

General

The primary business purpose of Enterprise Products GP, LLC is to manage the affairs and operations of Enterprise Products Partners L.P., a North American energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), and crude oil, and is an industry leader in the development of pipeline and other midstream infrastructure in the continental United States and

Gulf of Mexico. Enterprise Products Partners L.P. conducts substantially all of its business through a wholly owned subsidiary, Enterprise Products Operating L.P. (the Operating Partnership).

We are owned 99.99% by our limited partners and 0.01% by EPE Holdings. We, EPE Holdings, Enterprise Products GP and Enterprise Products Partners are under common control of Dan L. Duncan, the Chairman and the controlling shareholder of EPCO. We and Enterprise Products GP have no independent operations outside those of Enterprise Products Partners.

This annual report contains various forward-looking statements and information based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. Please read the section titled *Cautionary Statement Regarding Forward-Looking Information* under Item 1 of this annual report.

As generally used in the energy industry and in this document, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British Thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
Mdth	= thousand dekatherms
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Mcf	= thousand cubic feet

BASIS OF PRESENTATION

Currently, the parent company has no separate operating activities apart from those conducted by the Operating Partnership of Enterprise Products Partners. The principal sources of cash flow of the parent company are its investments in limited and general partner ownership interests of Enterprise Products Partners. The parent company s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The parent company s assets and liabilities are not available to satisfy the debts and other obligations of Enterprise Products Partners.

In order to fully understand the financial condition and results of operations of the parent company on a standalone basis, we have included discussions of parent company matters apart from those of our consolidated partnership. In general, the discussion of the parent company matters pertains to the period since its initial public offering on August 29, 2005.

Our historical consolidated financial information presented in this annual report on Form 10-K for periods prior to August 2005 has been presented using the consolidated financial information of Enterprise Products GP, which has been deemed the predecessor company of the parent company. For additional information regarding the basis of presentation of our consolidated financial information, please read Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

RECENT DEVELOPMENTS

Parent Company. In August 2005, we completed our initial public offering of 14,216,784 units (including an over-allotment amount of 1,616,784 units) at an offering price of $28.00 per unit. Total net proceeds from the sale of these units was approximately $373 million after deducting applicable underwriting discounts, commissions, structuring fees and other offering expenses of $25.6 million. The net proceeds from this initial public offering were used to reduce debt outstanding under our $525 Million Credit Facility.

In connection with our initial public offering, affiliates of EPCO contributed certain ownership interests in Enterprise Products Partners to us consisting of (i) 13,454,498 common units of Enterprise Products Partners acquired from an affiliate of El Paso Corporation (El Paso) in January 2005 and (ii) a 100% ownership interest in Enterprise Products GP. Concurrent with the contribution of these ownership interests, we assumed $160 million in debt and $0.5 million of accrued interest from EPCO.

In accordance with Statement of Financial Accounting Standard (SFAS) 141, we and the parent company recorded the transfer of such net assets from affiliates of EPCO at the transferors net historical carrying amounts of $160.6 million since both the transferors and transferee are under the common control of EPCO. As consideration for these transfers, affiliates of EPCO received 74,667,332 units (the sponsor units) of Enterprise GP Holdings L.P.

Enterprise Products Partners. The year 2005 was a challenging year for Enterprise Products Partners. The Gulf Coast region experienced two major hurricanes (Katrina and Rita) that affected our employees, suppliers, customers and industry. Our thoughts remain with those displaced by these storms and we are well-positioned to assist the Gulf Coast energy industry in the rebuilding effort. Although certain of our facilities incurred structural damage as a result of the storms and other operations were interrupted, by year-end the majority of our operated facilities were at pre-hurricane production, transportation or processing levels. In particular, our Toca natural gas processing facility, which is located in coastal Louisiana and was heavily damaged in Hurricane Katrina, has recently returned to operations. For information regarding our insurance claims related to these storms, please read Note 22 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our growth capital spending for 2005 was a record of $743.8 million, which includes $338.6 million for our Independence Hub offshore platform and related Independence Trail Pipeline and $90.1 million for our Constitution Oil and Constitution Gas Pipelines. In addition, we recently announced two new natural gas processing projects in the Rockies. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. In addition to our growth capital projects, we completed $326.6 million in acquisitions during 2005, the largest of which was the $145.5 million purchase of underground NGL storage facilities and propane terminals from Ferrellgas L.P. (Ferrellgas). For additional information regarding our growth capital spending and acquisitions, please read *Capital Spending* included within this Item 7.

During 2005, we completed the integration of our legacy operations with those of GulfTerra Energy Partners L.P. (GulfTerra). In September 2004, we completed the GulfTerra Merger transaction, whereby GulfTerra merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra s general partner (GulfTerra GP) became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso that are located in South Texas. For additional information regarding the GulfTerra Merger, please read Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our Cameron Highway Oil Pipeline began deliveries of Gulf of Mexico crude oil production during the first quarter of 2005 to major refining markets along the Texas Gulf Coast. The Cameron Highway Oil Pipeline can transport up to 500 MBPD of deepwater Gulf of Mexico crude oil production. We own a 50% interest in this system through our equity method investment in Cameron Highway Oil Pipeline Company.

We completed construction of the Constitution Oil and Constitution Gas Pipelines in 2005. We own and operate these pipelines, which provide production gathering services for the Constitution and Ticonderoga fields in the Gulf of Mexico. Initial throughput is expected on the Constitution pipelines during the first quarter of 2006.

In May 2003, GulfTerra commenced a project relating to its San Juan Basin assets. The San Juan Optimization Project was substantially complete in 2005 at an approximate cost of $31 million. This project resulted in a 10% increase of capacity on our San Juan Gathering System and will increase market opportunities through a new interconnect with the Transwestern Pipeline. We connected a record 336 natural gas wells to the San Juan Gathering System during 2005.

In October 2005, the Operating Partnership amended its revolving credit facility to increase total bank commitments from $750 million to $1.25 billion (which may be further increased to $1.4 billion upon our request, subject to certain conditions). The increase in borrowing capacity under our Multi-Year Revolving Credit Facility further enables us to meet future funding requirements of our growth capital projects. For additional information regarding our debt obligations, please see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

CAPITAL SPENDING

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of the business strategy of Enterprise Products Partners involves expansion through business combinations, growth capital projects and investments in joint ventures. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures. Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions.

We believe that we are positioned to continue to grow through construction of new facilities and acquisitions that will expand our system of assets and through growth capital projects. We estimate our consolidated capital spending during 2006 will approximate $1.8 billion, which includes estimated expenditures of approximately $1.7 billion for growth capital projects and acquisitions and approximately $78 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based upon our strategic operating and growth plans, which are also dependent upon our ability to generate capital from operating cash flows or otherwise obtain the capital necessary to accomplish our objectives. Our forecast may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Further, our forecast may change as a result of decisions made at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be the principal factor that determines how much we can spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

The following table summarizes our capital spending by activity for the periods indicated (dollars in thousands):

	For Year Ended December 31, 2005	2004	2003
Capital spending for business combinations and asset purchases:			
GulfTerra Merger:			
Cash payments to El Paso, including amounts paid to acquire certain South Texas midstream assets		$ 1,025,277	
Transaction fees and other direct costs		24,032	
Cash received from GulfTerra		(40,313)	
Net cash payments		1,008,996	
Value of non-cash consideration issued or granted		2,540,771	
Total GulfTerra Merger consideration		3,549,767	
Indirect interests in the Indian Springs natural gas gathering and processing assets	$ 74,854		
Additional ownership interests in Dixie Pipeline Company (Dixie)	68,608		
NGL underground storage and terminalling assets purchased from Ferrellgas	145,522		
Other business combinations and asset purchases	37,618	85,851	$ 37,348
Total	326,602	3,635,618	37,348
Capital spending for property, plant and equipment:			
Growth capital projects, net	743,827	114,419	125,600
Sustaining capital projects	73,622	32,509	20,313
Total	817,449	146,928	145,913
Capital spending attributable to unconsolidated affiliates:			
Purchase of 50% interest in GulfTerra GP in connection with the initial step of the GulfTerra Merger			425,000
Other investments in and advances to unconsolidated affiliates	88,044	64,412	46,927
Total	88,044	64,412	471,927
Total capital spending	$ 1,232,095	$ 3,846,958	$ 655,188

As shown in the preceding table, capital spending for growth capital projects is presented net of contributions in aid of construction costs of $47 million, $8.9 million and $0.9 million during 2005, 2004 and 2003, respectively. On certain of our capital projects, third parties may be obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins.

The significant capital spending transactions of Enterprise Products Partners during 2005 include the following:

We paid El Paso $74.9 million for indirect majority ownership interests in the 89-mile Indian Springs Gathering System and the Indian Springs natural gas processing facility, both of which are located in East Texas.

We paid $68.6 million for an additional 46% interest in Dixie from affiliates of ConocoPhillips and ChevronTexaco. As a result of these acquisitions, Dixie is now a majority-owned consolidated subsidiary of ours.

We purchased three NGL underground storage facilities and four propane terminals from Ferrellgas for $145.5 million in cash. The underground storage facilities are located in Kansas, Arizona and Utah and have a combined capacity of 6.1 MMBbls. Approximately 70% of the aggregate storage capacity is leased to third party customers under fee-based contracts. The four propane terminals are located in Minnesota and North Carolina. The Minnesota facilities are connected to our Mid-America Pipeline System, and the North Carolina terminals are connected by rail to our facilities on the Gulf Coast. As part of the transaction, Ferrellgas has contracted with us to maintain a certain level of storage volume and terminal throughput for five years with the option to extend for an additional five years.

Significant Recently Announced Growth Capital Projects of Enterprise Products Partners

Jonah Expansion. In February 2006, we and TEPPCO Partners, L.P. (TEPPCO), an affiliate of EPCO, entered into a letter of intent related to the formation of a joint venture to expand TEPPCO s Jonah Gas Gathering System (the Jonah system) located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d.

The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006.

The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

The general partner of TEPPCO and 2,500,000 common units of TEPPCO are owned by an affiliate of Mr. Duncan, Chairman of the board of directors of our general partner.

Piceance Basin Gas Processing Project. In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of the EnCana Corporation (EnCana). Under that agreement, we will have the right to process up to 1.3 Bcf/d of EnCana s natural gas production from the Piceance Basin area of western Colorado. To accommodate this production, we have begun construction of the Meeker natural gas processing facility in Rio Blanco County, Colorado. In addition, we will construct a 50-mile NGL pipeline that will connect our Meeker facility with our Mid-America Pipeline System. Phase I, which includes construction of the plant and pipeline, will provide us with 750 MMcf/d of natural gas processing capacity and the ability to recover up to 35 MBPD of NGLs. Phase II, which includes the expansion of the plant, will expand natural gas processing capacity at the facility to 1.3 Bcf/d and increase NGL extraction rates to up to 70 MBPD. We expect Phase I and Phase II to be operational by mid-2007 and late-2008, respectively. Phase I is expected to cost $284 million.

Wyoming Gas Processing Projects. In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and the general partner of Enterprise Products Partners, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d at an additional expected cost of $21 million. We expect this expansion to be completed in mid-2006.

We have also announced our intent to build a new gas processing plant with a capacity of 650 MMcf/d adjacent to the Pioneer plant. We expect to place the new facility in service during 2007. The Pioneer expansion and the new natural gas processing plant will serve growing natural gas production in the Jonah and Pinedale fields. The cost of this new processing facility is expected to be $228 million.

Natural Gas Storage Expansion. In December 2005, we completed the conversion of an existing brine well located at our Petal, Mississippi storage facility to a 2.4 Bcf natural gas storage cavern at a cost of $15 million. Due to strong demand for natural gas storage, we have commenced the development of an additional storage cavern at the Petal facility that is expected to add 5 Bcf of storage capacity. This cavern is expected to cost $75 million and be placed in service during the first quarter of 2008.

Expansion of Mont Belvieu NGL and Petrochemical Storage Services. In November 2005, we announced an expansion of our NGL and petrochemical storage services at our complex in Mont Belvieu, Texas to improve our ability to receive and deliver NGLs and petrochemicals. The Mont Belvieu expansion projects include the drilling of two new brine production wells and the construction of two above-ground brine storage pits. The increased brine storage capability will further enable us to enhance product storage services and movement to transportation and distribution pipelines that serve the Gulf Coast region, as well as our import and export facilities on the Houston Ship Channel. As a result of these projects, we will also more than double our above-ground brine storage capabilities to 19 MMBbls and will increase our capacity to produce brine. These projects are expected to be placed in service in 2006 and 2007 and are expected to cost $77 million.

Hobbs NGL Fractionator. In June 2005, we announced plans to construct a new NGL fractionator, designed to handle up to 75 MBPD of mixed NGLs, located at the interconnection of our Mid-America Pipeline System and our Seminole Pipeline near Hobbs, New Mexico. Additionally, we will construct a purity ethane storage well near the new fractionator and reconfigure the interconnection between our Mid-America Pipeline System and the Seminole Pipeline. These projects are expected to cost $175 million and be placed in service by mid-2007. Our Hobbs NGL fractionator will process the increase in mixed NGLs resulting from our Phase I expansion of the Mid-America Pipeline System.

Mid-America Pipeline System Phase I Expansion. In January 2005, we announced an expansion of the Rocky Mountain segment of our Mid-America Pipeline System to accommodate an expected increase in mixed NGLs originating from producing basins in Wyoming, Utah, Colorado and New Mexico. The expansion project will be completed in stages and will increase throughput volumes on the segment by a total of 50 MBPD. We expect final completion of the Phase I expansion during the second quarter of 2007 at a cost of $187 million. We expect to receive the necessary regulatory approval and begin construction on our Phase I expansion project in the first quarter of 2006.

Expansion of Mont Belvieu NGL Fractionator. In January 2005, we began a project to expand the processing capacity of our Mont Belvieu NGL fractionator from 210 MBPD to 225 MBPD and to reduce energy costs. This expansion project will enable us to accommodate a portion of an expected increase in NGL production from the Rocky Mountains. The project is expected to cost $41 million and be completed in mid-2006.

Independence Hub Platform and Independence Trail Pipeline System. In November 2004, we entered into an agreement with the Atwater Valley Producers Group for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas (collectively, the anchor fields) of the deepwater Gulf of Mexico. First production is expected in 2007.

We are constructing and will own the Independence Hub platform, which will be located in Mississippi Canyon Block 920, at a water depth of 8,000 feet. The Independence Hub is a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will process 1 Bcf/d of natural gas. The platform, which is estimated to cost $420 million, will be operated by Anadarko, and is designed to process production from its anchor fields and has excess payload capacity to support ten additional pipeline risers. In December 2004, we entered into an agreement with Cal Dive International Inc.(Cal Dive) to sell them a 20% indirect interest in the Independence Hub platform.

Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of 1 Bcf/d of natural gas. The pipeline system, which is estimated to cost $268 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. In connection with the regulations for hazardous liquid pipelines, we developed a pipeline integrity management program in 2002. In connection with the regulations for natural gas pipelines, we developed a pipeline integrity management program in 2004.

During 2005, we spent approximately $42.2 million to comply with these programs, of which $25 million was recorded as an operating expense, and the remaining $17.2 million was capitalized. We spent approximately $22.4 million to comply with these programs during 2004, of which $14.9 million was recorded as an operating expense and the remaining $7.5 million was capitalized.

We expect our net cash outlay for pipeline integrity program expenditures to approximate $63.2 million during 2006. Our forecast is net of certain costs we expect to recover from El Paso. In April 2002, GulfTerra acquired several midstream assets located in Texas and New Mexico from El Paso. These assets include the Texas Intrastate System and the Permian Basin System. El Paso agreed to indemnify GulfTerra for any pipeline integrity costs it incurred (whether paid or payable) during 2005, 2006 and 2007 with respect to such assets, to the extent that such annual costs exceed $3.3 million; however, the aggregate amount reimbursable by El Paso for these periods is capped at $50.2 million. During 2006, we expect to recover $13.8 million from El Paso related to our 2005 expenditures, which leaves a remainder of $36.4 million reimbursable by El Paso for 2006 and 2007 pipeline integrity costs.

RESULTS OF OPERATIONS

Parent Company s Results of Operations

The parent company has no separate operating activities apart from those conducted by Enterprise Products Partners and its Operating Partnership. The principal sources of earnings for the parent company are its equity investments in limited and general partner ownership interests of Enterprise Products Partners. The following table summarizes the key components of the results of operations of the parent company since its formation in April 2005 (in thousands).

Equity in income of unconsolidated affiliates	$	24,507
Interest expense	$	3,445
Net income	$	20,631

For additional information regarding the financial results of the parent company, please see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. The following is a discussion of the highlights of the parent company s results of operations since its initial public offering in August 2005.

Equity income. The parent company recorded $24.5 million in equity earnings from its investments in Enterprise Products Partners limited and general partner ownership interests. Of this amount, $19.9 million results from its investment in the general partner of Enterprise Products Partners and the remainder from its investment in 13,454,498 common units of Enterprise Products Partners.

Interest expense. The parent company recorded $3.4 million in interest expense during the period primarily due to borrowings incurred under its $525 Million Credit Facility. Included in this interest expense amount is $0.3 million related to the $160 million in principal amount of debt the parent company assumed from affiliates of EPCO in August 2005. The assumed debt was repaid in late August 2005 using borrowings under the parent company s $525 Million Credit Facility.

Our Consolidated Results of Operations

Since the parent company owns the general partner of Enterprise Products Partners, it controls the activities of Enterprise Products GP and Enterprise Products Partners. As a result, the parent company consolidates the financial information of these subsidiaries with that of its own.

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services, and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology employed) and products produced and/or sold.

We evaluate segment performance based on the non-generally accepted accounting principle (non-GAAP) financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The financial measure calculated using accounting principles generally accepted in the United States of America (GAAP) most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (i) depreciation and amortization expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

For additional information regarding our business segments, please read Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

We have historically included equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be suppliers of raw materials or consumers of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system in a number of ways, including an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we earn revenues based on volume or an ownership of products such as NGLs.

Many of our equity investments are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate.

For additional information regarding our investments in and advances to unconsolidated affiliates, please read Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Selected Price and Volumetric Data

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products since the beginning of 2003:

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2003									
1st Quarter	$6.58	$34.12	$0.43	$0.65	$0.76	$0.80	$0.85	$0.24	$0.21
2nd Quarter	$5.40	$29.04	$0.39	$0.53	$0.58	$0.62	$0.65	$0.25	$0.19
3rd Quarter	$4.97	$30.21	$0.37	$0.56	$0.67	$0.68	$0.73	$0.21	$0.15
4th Quarter	$4.58	$31.18	$0.40	$0.58	$0.73	$0.71	$0.75	$0.22	$0.16
Average for Year	$5.38	$31.14	$0.40	$0.58	$0.68	$0.70	$0.74	$0.23	$0.18
2004									
1st Quarter	$5.69	$35.25	$0.43	$0.66	$0.76	$0.76	$0.87	$0.29	$0.26
2nd Quarter	$6.00	$38.34	$0.45	$0.65	$0.79	$0.79	$0.92	$0.32	$0.26
3rd Quarter	$5.75	$43.90	$0.52	$0.79	$0.92	$0.92	$1.05	$0.32	$0.27
4th Quarter	$7.07	$48.31	$0.60	$0.85	$1.03	$1.04	$1.15	$0.40	$0.35
Average for Year	$6.13	$41.45	$0.50	$0.74	$0.88	$0.88	$1.00	$0.33	$0.29
2005									
1st Quarter	$6.27	$49.68	$0.52	$0.79	$0.98	$1.00	$1.14	$0.45	$0.39
2nd Quarter	$6.74	$53.09	$0.52	$0.82	$0.98	$1.01	$1.16	$0.37	$0.30
3rd Quarter	$8.53	$63.08	$0.69	$0.97	$1.14	$1.26	$1.36	$0.37	$0.33
4th Quarter	$13.00	$60.03	$0.76	$1.06	$1.27	$1.34	$1.36	$0.50	$0.44
Average for Year	$8.64	$56.47	$0.62	$0.91	$1.09	$1.15	$1.26	$0.42	$0.37

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service (OPIS) and Chemical Market Associates, Inc. (CMAI). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents an average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests, and reflect the periods in which we owned an interest in such operations. In general, the increase in volumes since 2003 is due to the assets we acquired in connection with the GulfTerra Merger, which was completed on September 30, 2004.

	For Year Ended December 31,		
	2005	**2004**	**2003**
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,478	1,411	1,275
NGL fractionation volumes (MBPD)	292	307	227
Equity NGL production (MBPD)	85	95	43
Fee-based natural gas processing (MMcf/d)	1,767	1,692	194
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	5,916	5,638	600
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,780	2,081	433
Crude oil transportation volumes (MBPD)	127	138	
Platform gas processing (BBtus/d)	252	306	
Platform oil processing (MBPD)	7	14	
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	81	76	77
Propylene fractionation volumes (MBPD)	55	57	57
Octane additive production volumes (MBPD)	6	10	4
Petrochemical transportation volumes (MBPD)	64	71	68
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,669	1,620	1,343
Natural gas transportation volumes (BBtus/d)	7,696	7,719	1,033
Equivalent transportation volumes (MBPD) (1)	3,694	3,651	1,615

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Results of Our Consolidated Operations

The most significant recent event affecting our results of operations was the GulfTerra Merger and related transactions. Since the closing date of the GulfTerra Merger was September 30, 2004, our Statements of Consolidated Operations do not include any earnings from GulfTerra prior to October 1, 2004. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Statements of Consolidated Operations for 2004 include four months of earnings from the South Texas midstream assets. The results of operations from our other 2005, 2004 and 2003 business combinations and asset purchases are also included in our earnings from the date of their respective acquisitions.

The following table summarizes the key components of our consolidated results of operations for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2005	**2004**	**2003**
Revenues	$ 12,256,959	$ 8,321,202	$ 5,346,431
Operating costs and expenses	11,546,225	7,904,336	5,046,777
General and administrative costs	64,194	47,264	39,164
Equity in income (loss) of unconsolidated affiliates	14,548	52,787	(13,960)
Operating income	661,088	422,389	246,530
Interest expense	249,002	161,589	140,806

Minority interest expense	353,642	229,607	91,079
Net income	55,276	29,778	15,861

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 67% of total consolidated revenues for each of 2005 and 2004 and 68% of total consolidated revenues for 2003. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11%, 13% and 12% of total consolidated revenues for 2005, 2004 and 2003, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13%, 10% and 11% of total consolidated revenues for 2005, 2004 and 2003, respectively.

Minority interest expense represents third-party and related party ownership interests in the earnings of Enterprise Products Partners and certain other subsidiaries. For financial reporting purposes, the assets and liabilities of our majority-owned subsidiaries are consolidated with those of our own, with any third-party investor's ownership in our consolidated balance sheet amounts shown as minority interest. For additional information regarding our minority interest amounts, please see Note 2 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our consolidated gross operating margin by segment and in total is as follows for the periods indicated (dollars in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Gross operating margin by segment:			
NGL Pipelines & Services	$ 579,706	$ 374,196	$ 310,677
Onshore Natural Gas Pipelines & Services	353,076	90,977	18,345
Offshore Pipeline & Services	77,505	36,478	5,561
Petrochemical Services	126,060	121,515	75,885
Other, non-segment		32,025	(53)
Total segment gross operating margin	$ 1,136,347	$ 655,191	$ 410,415

For a reconciliation of our consolidated non-GAAP gross operating margin to our consolidated GAAP operating income and further to our consolidated GAAP income before provision for taxes, minority interest and cumulative effect of changes in accounting principles, please read "*Other Items*" included within this Item 7.

Comparison of Year Ended December 31, 2005 with Year Ended December 31, 2004

Revenues for 2005 increased $3.9 billion over those recorded during 2004. The trend in consolidated revenues can be attributed to (i) a $2.2 billion increase in revenues from our NGL and petrochemical marketing activities resulting from an increase in sales volumes and energy commodity prices in 2005 relative to 2004; (ii) the addition of $1.5 billion in revenues from acquired or consolidated businesses, particularly those generated by the GulfTerra and South Texas midstream assets and (iii) a $0.2 billion increase in revenues from the sale of natural gas attributable to higher natural gas prices year-to-year.

Consolidated costs and expenses increased $3.7 billion year-to-year primarily due to (i) higher energy commodity prices, which resulted in a $2.2 billion increase in the cost of sales of natural gas, NGLs and petrochemical products and (ii) the addition of $1.4 billion in costs and expenses attributable to acquired or consolidated businesses. General and administrative costs increased $16.9 million period-to-period as a result of our expanded business activities.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was 91 cents per gallon (CPG) during 2005 versus 73 CPG during 2004 a year-to-year increase of 25%. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $8.64 per MMBtu during 2005 versus $6.13 per MMBtu during 2004. Polymer grade propylene index prices increased 27% year-to-year and refinery grade propylene index prices increased 28% year-to-year. For historical pricing information of natural gas, crude oil and NGLs, please see the table on page 58.

Equity earnings from unconsolidated affiliates decreased $38.2 million year-to-year. Equity earnings for 2005 include a full year of our share of earnings from investments we acquired in connection with the GulfTerra Merger, including an $11.5 million charge associated with the refinancing of Cameron Highway s project debt. Fiscal 2004 includes $32 million of equity earnings from GulfTerra GP, which we consolidated in September 2004 as a result of completing the GulfTerra Merger. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $238.7 million increase in operating income year-to-year.

Interest expense increased $87.4 million year-to-year primarily due to debt we incurred in 2004 as a result of the GulfTerra Merger, the issuance of additional senior notes in 2005 and from borrowings under the parent company s $525 Million Credit Facility. Our average debt principal outstanding was $4.9 billion in 2005 compared to $2.9 billion in 2004.

As a result of items noted in the previous paragraphs, net income increased $25.5 million year-to-year to $55.3 million in 2005 compared to $29.8 million in 2004.

Due to our geographic and business diversification, Hurricanes Katrina (August 2005) and Rita (September 2005) had varying effects across our business segments. The hurricanes impacted supply and demand for natural gas, NGLs, crude oil and motor gasoline. In general, this resulted in an increase in energy commodity prices, which was exacerbated in certain regions due to local supply and demand imbalances. The disruptions in natural gas, NGL and crude oil production along the U.S. Gulf Coast resulted in decreased volumes for some of our pipeline systems, natural gas processing plants and NGL fractionators, which in turn caused a decrease in our gross operating margin from certain operations. In addition, operating costs at certain of our plants and pipelines were negatively impacted due to the higher fuel costs. These adverse effects were mitigated by increases in gross operating margin from certain of other operations, which benefited from increased demand for NGLs and octane additives, regional demand for natural gas and the general increase in commodity prices.

We estimate that Hurricanes Katrina and Rita reduced our gross operating margin in 2005 by approximately $48 million as a result of decreased transportation and processing volumes and higher hurricane-related expenses and insurance premium costs. Our 2005 results of operations reflect a $4.8 million cash receipt related to the settlement of certain business interruption insurance claims from Hurricane Ivan in September 2004.

We are at varying stages of the insurance claims process with respect to these hurricanes and expect to receive additional insurance recoveries in 2006 and 2007. For additional information regarding our insurance claims related to these storm events, please read *Results of Operations Significant Risks and Uncertainties Hurricanes* included within this Item 7.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $579.7 million for 2005 versus $374.2 million for 2004. The $205.5 million increase in gross operating margin consists of the following: (i) a $186.9 million increase from natural gas processing and related NGL marketing activities, (ii) a $21.3 million increase from NGL fractionation and (iii) a $2.7 million decrease from NGL pipelines and related storage services.

The $186.9 million year-to-year increase in gross operating margin from natural gas processing and related NGL marketing activities includes $122.3 million from natural gas plants acquired in connection with the GulfTerra Merger and $66.9 million from NGL marketing activities. Our marketing activities benefited from higher sales volumes and commodity prices during 2005 compared to 2004.

The $21.3 million year-to-year increase in gross operating margin from NGL fractionation includes (i) $14.9 million of improved results from our Mont Belvieu facility, (ii) $14 million from assets acquired in connection with the GulfTerra Merger and (iii) a $9 million decrease from our Louisiana NGL fractionators, particularly Norco, which suffered a loss of processing volumes due to Hurricane Katrina. Our Norco NGL fractionator is expected to return to normal operating rates during 2006.

The $2.7 million year-to-year decrease in gross operating margin from NGL pipelines and related storage services was due to a variety of reasons, including (i) a net $11.2 million decrease from our Mid-America Pipeline System and Seminole Pipeline primarily due to higher fuel costs and pipeline integrity expenses, (ii) a $4.9 million decrease from our Louisiana Pipeline System primarily due to hurricane effects, (iii) a net $6.9 million increase from our import and export facilities and related Houston Ship Channel pipeline attributable to increased volumes, and (iv) a net $8.9 million increase due to acquired assets and consolidation of former equity method investees.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $353.1 million for 2005 compared to $91 million for 2004. The $262.1 million increase in gross operating margin is primarily due to onshore natural gas pipelines and storage assets acquired in connection with the GulfTerra Merger. Gross operating margin from this segment is largely attributable to contributions from our San Juan Gathering System, Texas Intrastate System and Permian Basin System, which together generated gross operating margins in 2005 of $290.4 million. Our Petal and Hattiesburg natural gas storage facilities generated $38.7 million of gross operating margin in 2005. The San Juan Gathering System, Texas Intrastate System, Permian Basin System and Petal and Hattiesburg natural gas storage facilities were acquired in connection with the GulfTerra Merger.

Offshore Pipelines & Services. Gross operating margin from this business segment was $77.5 million for 2005 compared to $36.5 million for 2004. The $41 million increase in gross operating margin is primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger. The year-to-year change in gross operating margin consists of the following: (i) a $20.1 million increase from offshore natural gas pipelines, (ii) a $26.4 million increase from offshore platforms and (iii) a $5.5 million decrease from offshore crude oil pipelines, which includes an $11.5 million charge related to the refinancing of Cameron Highway s project debt in 2005.

Petrochemical Services. Gross operating margin from this business segment was $126.1 million for 2005 compared to $121.5 million during 2004. The $4.6 million increase in gross operating margin is primarily due to improved results from isomerization services and octane additive production activities, both of which benefited from increased demand for motor gasoline in 2005.

Other. Gross operating margin from this segment pertains to equity earnings we recorded from GulfTerra GP prior to its consolidation with our financial results in September 2004.

Comparison of Year Ended December 31, 2004 with Year Ended December 31, 2003

Revenues for 2004 increased $3 billion over those recorded during 2003. The increase in consolidated revenues can be attributed to (i) a $2.1 billion increase in revenues from our NGL and petrochemical marketing activities primarily resulting from an increase in sales volumes and energy commodity prices in 2004 relative to 2003 and (ii) the addition of $0.8 billion in revenues from acquired assets and business combinations, particularly those resulting from the GulfTerra Merger in September 2004.

Consolidated costs and expenses increased $2.9 billion year-to-year primarily due to (i) higher energy commodity prices, which resulted in a $2 billion increase in the cost of sales of our NGL and petrochemical marketing activities; (ii) the addition of $0.6 billion in costs and expenses attributable to acquired or consolidated businesses during 2004; and (iii) a $0.2 billion increase in the costs of our natural gas processing business primarily due to an increase in volumes. General and administrative costs increased $8.1 million year-to-year as a result of expanded business activities.

As noted previously, changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was 73 CPG during 2004 versus 57 CPG during 2003 a year-to-year increase of 28%. The market price of natural gas averaged $6.13 per MMBtu during 2004 versus $5.38 per MMBtu during 2003. Polymer grade propylene index prices increased 44% year-to-year and refinery grade propylene index prices increased 61% year-to-year.

Equity earnings from unconsolidated affiliates increased $66.7 million year-to-year. Fiscal 2004 includes $32 million of equity earnings from GulfTerra GP, which we acquired in December 2003. Fiscal 2003 includes a $22.5 million non-cash asset impairment charge related to our octane additive production facility. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $175.9 million increase in operating income year-to-year.

Interest expense increased $21.6 million year-to-year primarily due to debt we incurred in 2004 as a result of the GulfTerra Merger. Our average debt principal outstanding was $2.9 billion during 2004 compared to $2 billion during 2003.

As a result of the items noted in previous paragraphs, net income increased $13.9 million to $29.8 million for 2004 compared to $15.9 million for 2003.

The following information highlights the significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $374.2 million for 2004 versus $310.7 million for 2003. The $63.5 million increase in gross operating margin includes (i) a $82 million increase from our natural gas processing business, which includes $61.2 million from assets acquired in connection with the GulfTerra Merger, (ii) a $20.9 million decrease from our NGL pipelines and related storage services resulting from an increase in pipeline integrity expenses and a decrease in transportation volumes on certain of our pipelines and (iii) a $6.8 million increase from our NGL fractionation business, which includes $5.8 million associated with the South Texas NGL fractionators we acquired in connection with the GulfTerra Merger.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $91 million for 2004 compared to $18.3 million for 2003. The $72.7 million increase in gross operating margin for this segment is also attributable to assets acquired in connection with the GulfTerra Merger.

Offshore Pipelines & Services. Gross operating margin from this business segment was $36.5 million for 2004 compared to $5.6 million for 2003. The $30.9 million increase from this segment is primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger.

Petrochemical Services. Gross operating margin from this business segment was $121.5 million in 2004 compared to $75.9 million in 2003. Gross operating margin from our octane additive production business increased $34.4 million year-to-year primarily due to our consolidation of the results of operations of Belvieu Environmental Fuels (BEF). We acquired a controlling ownership interest in BEF, which owns our octane additive production facility, in September 2003. In addition, the results of operations for 2003 include the recognition by us of our share (or $22.5 million) of a $67.5 million non-cash asset impairment charge recorded by BEF prior to its consolidation. Gross operating margin from propylene fractionation increased $10.1 million year-to-year primarily due to higher petrochemical marketing sales volumes, which benefited from the effects of higher polymer grade propylene prices in 2004 relative to 2003.

Significant Risks and Uncertainties   Hurricanes

The following is a discussion of the general status of insurance claims related to recent hurricanes that affected our assets. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation for the GulfTerra Merger includes a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain GulfTerra assets caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004 prior to the GulfTerra Merger. These expenditures represent our costs to restore the damaged facilities to operation. Since this loss event occurred prior to completion of the GulfTerra Merger, the claim was filed under the insurance program of GulfTerra and El Paso. Since year end 2005, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million by mid-2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the fourth quarter of 2005, we received $4.8 million from such claims. In addition, we estimate an additional $15 million to $16 million will be received during the first quarter of 2006. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period in which funds are received.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection, evaluation of property damage to our facilities and repairs are a continuing effort. We expensed $5 million during the third quarter of 2005 related to property damage insurance deductibles for these storms. To the extent that insurance proceeds from property damage claims do not cover our actual cash expenditures (in excess of the insurance deductibles we have expensed), such shortfall will be expensed when realized. We recorded $15.5 million of estimated recoveries from property damage claims based on amounts expended through December 31, 2005. In addition, we expect to file business interruption claims for losses related to these hurricanes. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

General Outlook for 2006

We expect our results of operations to be affected by the following key trends and events during 2006.

We believe that drilling activity in the major producing areas where we operate, including the Rocky Mountains and San Juan Basin and deepwater Gulf of Mexico will result in increased demand for our midstream energy services. As a result, we expect higher transportation and processing volumes for our assets due to increased natural gas and crude oil production from both the Rocky Mountains and deepwater Gulf of Mexico. Hurricanes Katrina and Rita reduced natural gas and crude oil production in the Gulf of Mexico during the latter half of 2005. Barring any other major storms or similar disruptions, we believe that Gulf of Mexico production will return to pre-hurricane levels by mid-2006.

We are currently in a major construction phase that began in 2005. With several major projects underway and announced to begin this year, fiscal 2006 will be a transition year as we continue to invest in multiple projects that will further diversify our portfolio of midstream assets. We believe that completion of these projects will generate additional cash flows beginning in 2006. Our significant growth capital projects are supported by long-term agreements with producers in

significant supply basins, which include the Piceance Basin in Colorado, the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming and the deepwater Gulf of Mexico.

We believe that our natural gas and NGL facilities located in central Louisiana and our Marco Polo Oil Pipeline, Marco Polo platform and Cameron Highway Oil Pipeline located in the Gulf of Mexico are poised to benefit as production volumes increase from developments in the Southern Green Canyon area of the deepwater Gulf of Mexico. Volumes on our Cameron Highway Oil Pipeline were adversely affected during the fourth quarter of 2005 due to disruption of production caused by Hurricanes Katrina and Rita, and these volumes are expected to continue to be adversely affected during the first quarter of 2006. However, we currently expect significant increases in Cameron Highway Oil Pipeline volumes during the remainder of 2006 as production increases, including production at the Mad Dog field and initial production from the Ticonderoga, K2 North and Timon fields.

We believe that the strength of the domestic and global economy will continue to drive increased demand for all forms of energy despite higher commodity prices. Our largest NGL consuming customers in the ethylene industry continue to see strong demand for their products, which enables them to raise prices to mitigate higher fuel and feedstock costs. With the unusually high price of crude oil relative to natural gas, ethane and propane are the preferred feedstocks for the ethylene industry.

LIQUIDITY AND CAPITAL RESOURCES

Parent Company Liquidity and Capital Resources

The parent company has no separate operating activities apart from those conducted by Enterprise Products Partners and its Operating Partnership. The primary sources of cash flow for the parent company are its investments in the limited and general partner ownership interests of Enterprise Products Partners. The amount of cash that Enterprise Products Partners can distribute to its partners, including the parent company, each quarter is based on earnings from Enterprise Products Partners business activities, which are exposed to certain risks. For a summary of these risks, please read *Risk Factors* included under Item 1A of this annual report.

The parent company s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The parent company expects to fund its short-term needs for such items as general and administrative expenses with operating cash flows. Debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements. Our partner company expects to fund cash distributions to its partners primarily with operating cash flows.

In August 2005, the parent company completed its initial public offering of 14,216,784 units (including an over-allotment amount of 1,616,784 units) at an offering price of $28.00 per unit. Total net proceeds from the sale of these units was approximately $373 million after deducting applicable underwriting discounts, commissions, structuring fees and other offering expenses of $25.6 million. The net proceeds from this initial public offering were used to reduce debt outstanding under the parent company s $525 Million Credit Facility.

In November 2005, the parent company received a total of $27.2 million in cash distributions in connection with its general and limited partner ownership interests in Enterprise Products Partners and used $19 million of this distribution to reduce indebtedness under its bank credit facility and the remaining $8.2 million to pay a pro rata distribution to its partners for the period August 30, 2005 through September 30, 2005.

Parent Company Debt Obligations

$525 Million Credit Facility. In August 2005, the parent company entered into a $525 million credit facility consisting of a $475 million term loan and a $50 million revolving credit facility. At the time of its initial public offering, the parent company borrowed $525 million under this facility to repay (i) $365 million of indebtedness owed by its subsidiary, Enterprise Products GP, to an affiliate of EPCO and (ii) $160 million of debt assumed from EPCO. The $365 million owed by Enterprise Products GP was incurred in September 2004 as a result of its purchase of a 50% interest in the general partner of GulfTerra from El Paso. The $160 million in assumed debt relates to EPCO s contribution of net assets to the parent company in August 2005.

The parent company used net proceeds from its initial public offering in August 2005 to repay $350.5 million owed under the $525 Million Credit Facility. At December 31, 2005, $124.5 million was outstanding under the term loan portion of this facility and $10 million under the revolving credit portion. Debt principal outstanding under the $525 Million Credit Facility was due in February 2006. In January 2006, the parent company amended and restated its $525 Million Credit Facility with the result being a new $200 Million Credit Facility.

$200 Million Credit Facility. In January 2006, the parent company amended and restated its $525 Million Credit Facility to reflect a new borrowing capacity of $200 million, which includes a sublimit of $25 million for letters of credit. Amounts borrowed under the new $200 Million Credit Facility are due in January 2009. Borrowings under this credit agreement are secured by a pledge of (i) 13,454,498 common units of Enterprise Products Partners L.P and (ii) ownership interests in Enterprise Products GP that are owned by the parent company.

Amounts borrowed under this credit agreement bear interest at a variable interest rate selected by the parent company at the time of each borrowing equal to (i) the greater of (a) the prime rate publicly announced by Citibank N.A. or (b) the Federal Funds Effective Rate plus 0.5% or (ii) a Eurodollar rate. Variable interest rates based on either the prime rate or Federal Funds Effective Rate will be increased by an applicable margin of up to 0.75%. Variable interest rates based on Eurodollar rates will be increased by an applicable margin ranging from 1% to 1.75%.

The $200 Million Credit Facility contains various covenants related to the parent company s ability, and the ability of certain defined subsidiaries of the parent company (which defined subsidiaries exclude Enterprise Products GP and Enterprise Products Partners), to incur certain indebtedness, grant certain liens, make fundamental structural changes, make distributions following an event of default and enter into certain restricted agreements. The credit agreement also requires the parent company to satisfy certain quarterly financial covenants including (i) its leverage ratio must not exceed 4.5 to 1, except under certain circumstances, and (ii) its minimum net worth must exceed $525 million.

Our Consolidated Liquidity and Capital Resources

Our primary consolidated cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures, business acquisitions and distributions to our partners and minority interests. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources (either separately or in combination) including cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional equity and debt securities. We expect to fund cash distributions to partners and minority interests primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2005, we had $42.7 million of unrestricted cash on hand, $40 million of available credit under the revolving portion of the parent company s $525 Million Credit Facility and $727 million of available credit under the Operating Partnership's Multi-Year Revolving

Credit Facility. In

total, we had approximately $5 billion in principal outstanding under various debt agreements at December 31, 2005.

As a result of Enterprise Products Partners growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that financing arrangements to support our growth activities can be obtained on reasonable terms. Furthermore, we believe that maintenance of the Operating Partnership s credit ratings, combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently, provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

For additional information regarding Enterprise Products Partners growth strategy, please read *Capital Spending* included within this Item 7.

Credit Ratings

At February 15, 2006, the credit ratings of the Operating Partnership s debt securities were Baa3 with a stable outlook as rated by Moody s Investor Services; BBB- with a stable outlook as rated by Fitch Ratings and BB+ with a stable outlook as rated by Standard and Poor s. There are no credit ratings with respect to the parent company.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, the Operating Partnership entered into a $54 million, ten-year, fixed-rate loan with the Mississippi Business Finance Corporation (MBFC). The indenture agreement for this loan contains an acceleration clause whereby if the Operating Partnership s credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or lower, the $54 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, the Operating Partnership would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

Registration Statements

From time-to-time, Enterprise Products Partners may issue equity or debt securities to meet its liquidity and capital spending requirements. In March 2005, Enterprise Products Partners filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of equity and debt securities. After taking into account the issuance of securities under this universal registration statement during 2005, Enterprise Products Partners can issue an additional $3.4 billion of securities under this registration statement as of February 15, 2006.

During 2003, Enterprise Products Partners instituted a distribution reinvestment plan (DRIP). The DRIP provides unitholders of record and beneficial owners of common units of Enterprise Products Partners a voluntary means by which they can increase the number of common units they own in Enterprise Products Partners by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of Enterprise Products Partners. Enterprise Products Partners has a registration statement on file with the SEC covering the issuance of up to 15,000,000 common units in connection with the DRIP. A total of 10,925,102 common units have been issued under this registration statement through February 15, 2006.

Enterprise Products Partners also has a registration statement on file related to its employee unit purchase plan, under which Enterprise Products Partners can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase Enterprise Products Partners common units at a 10% discount through payroll deductions. A total of 260,222 common units have been issued to employees under this plan through February 15, 2006.

In November 2005, the parent company filed a registration statement covering the potential future issuance of 250,000 of its units in connection with a long-term incentive plan (the 2005 Plan). The 2005 Plan was established to encourage directors of EPE Holdings and employees of EPCO that perform services for us to increase their ownership of parent company units and to develop a sense of proprietorship and personal involvement in the parent company s and Enterprise Products Partners business and financial success. The 2005 Plan provides for the future issuance of unit options, restricted units or phantom units of the parent company (limited to 250,000 units). No awards have been issued under the 2005 Plan as of February 15, 2006.

Debt Obligations

For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. The following table summarizes our consolidated debt obligations at the dates indicated (dollars in thousands):

	December 31, 2005	**2004**
Parent Company debt obligations:		
$525 Million Credit Facility, amended and restated January 2006 (1)	$ 134,500	
Operating Partnership debt obligations:		
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (2)		$ 242,229
Multi-Year Revolving Credit Facility, variable rate, due October 2010	490,000	321,000
Seminole Notes, 6.67% fixed-rate, repaid December 2005		15,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005		350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015 (3)	250,000	
Senior Notes J, 5.75% fixed-rate, due March 2035 (4)	250,000	
Senior Notes K, 4.950% fixed-rate, due June 2010 (5)	500,000	
Enterprise Products GP related party obligation:		
$370 Million Note to Dan Duncan LLC, 6.25% fixed-rate, repaid August 2005		366,433
Dixie Revolving Credit Facility, variable rate, due June 2007	17,000	
Debt obligations assumed from GulfTerra	5,067	6,469
Total principal amount	5,000,567	4,655,131
Other, including unamortized discounts and premiums and changes in fair value (6)	(32,287)	(7,462)
Subtotal long-term debt	4,968,280	4,647,669
Less current maturities of debt (7)		(18,450)
Long-term debt	$ 4,968,280	$ 4,629,219
Standby letters of credit outstanding	$ 33,129	$ 139,052

(1) The parent company amended and restated this credit facility in January 2006 resulting in a new $200 Million Credit Facility.

(2) Enterprise Products Partners used proceeds from its February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility.

(3) Senior Notes I were issued at 99.379% of their face amount in February 2005.

(4) Senior Notes J were issued at 98.691% of their face amount in February 2005.

(5) Senior Notes K were issued at 99.834% of their face amount in June 2005.

(6) The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. The December 31, 2004 amount includes $1.8 million related to fair value hedges and $9.2 million in net unamortized discounts.

(7) In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," long-term and current maturities of debt at December 31, 2004, reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment in February 2005 of the Operating Partnership s 364-Day Acquisition Credit Facility using proceeds from an Enterprise Products Partners equity offering.

Our significant debt-related transactions during 2005 were as follows:

In February 2005, the Operating Partnership completed repayment of its 364-Day Acquisition Credit Facility using proceeds from an Enterprise Products Partners equity offering.

Also in February 2005, the Operating Partnership issued $500 million in aggregate principal amount of Senior Notes I and J. A portion of the proceeds from these Senior Notes were used to repay Senior Notes A, which matured in March 2005.

In June 2005, the Operating Partnership issued $500 million in aggregate principal amount of Senior Notes K.

In August 2005, the parent company entered into its $525 Million Credit Facility in connection with its initial public offering.

In October 2005, the borrowing capacity under the Operating Partnership s Multi-Year Revolving Credit Facility was increased from $750 million to $1.25 billion, with the possibility that the borrowing capacity could be increased further to $1.4 billion (subject to certain conditions). In addition, the maturity date for debt outstanding under this facility was extended from September 2009 to October 2010.

In December 2005, Seminole Pipeline Company, a majority-owned subsidiary, made the final payment on its indebtedness.

We have three unconsolidated affiliates with long-term debt obligations. The following table summarizes the debt obligations of these unconsolidated affiliates (on a 100% basis to the joint venture) at December 31, 2005 and our ownership interest in each entity on that date (dollars in thousands):

	Our Ownership Interest	**Total**
Cameron Highway	50.0%	$ 415,000
Poseidon	36.0%	95,000
Evangeline	49.5%	30,650
Total		$ 540,650

For information regarding the scheduled maturities of our consolidated debt obligations and estimated cash payments for interest, please read *Contractual Obligations* within this Item 7.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in thousands). For information regarding the individual components of our cash flow amounts, please see the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For Year Ended December 31,		
	2005	**2004**	**2003**
Net cash provided from operating activities	$ 614,101	$ 388,373	$ 426,706
Net cash used in investing activities	1,130,394	1,311,424	662,076
Net cash provided by financing activities	533,937	917,591	247,556

We prepare our Statements of Consolidated Cash Flows using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and the like, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, and (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of assets or gains or losses from the extinguishment of debt. In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory balances are influenced by changes in commodity prices and the quantity of prices held in connection with our marketing activities.

In addition, noncash items that were subtracted in determining income must be added back in determining net cash flows from operating activities. Each of these noncash items is a charge against income but does not decrease cash. Items to be added back include depreciation, amortization of intangibles, amortization in interest expense, operating lease expense paid by EPCO, provisions for impairments of long-lived assets, minority interest and increases in deferred tax liabilities. Conversely, noncash items that were added in determining income (such as amortization of bond premiums or decreases in deferred tax liabilities) must be subtracted in determining net cash flows from operating activities.

Equity in income or loss from unconsolidated affiliates is also a non-cash item that must be removed in determining net cash flows from operating activities. Our cash flows from operating activities reflect the actual cash distributions we receive from such investees.

Net cash provided from operating activities is largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and crude oil. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from other service providers or producers due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities. For a more complete discussion of these and other risk factors pertinent to our business, please read Item 1A of this annual report.

Cash used in investing activities primarily represents expenditures for capital projects, business combinations, asset purchases and investments in unconsolidated affiliates. Cash provided by (or used in) financing activities generally consists of borrowings and repayments of debt, contributions from and distributions to minority interests, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant year-to-year variances in our cash flow amounts:

Comparison of Year Ended December 31, 2005 with Year Ended December 31, 2004

Operating activities. Net cash provided from operating activities was $614.1 million in 2005 compared to $388.4 million in 2004. The $225.7 million, or 58%, year-to-year increase in net cash provided from operating activities is primarily due to:

Net income adjusted for all non-cash items and the net effects of changes in operating accounts increased $237.7 million year-to-year primarily due to the addition of earnings from assets acquired in connection with the GulfTerra Merger in September 2004.

Distributions received from unconsolidated affiliates decreased by $12 million year-to-year primarily due to the consolidation of GulfTerra GP in September 2004 partially offset by increased cash distributions from offshore Gulf of Mexico investments. GulfTerra GP accounted for $32.3 million in cash distributions from unconsolidated affiliates during 2004.

The carrying value of our inventories increased from $189 million at December 31, 2004 to $339.6 million at December 31, 2005. The $150.6 million increase is primarily due to higher commodity prices during 2005 when compared to 2004 and an increase in volumes purchased and held in inventory in connection with our marketing activities at December 31, 2005 versus December 31, 2004.

Investing activities. Cash used in investing activities was $1.1 billion in 2005 compared to $1.3 billion in 2004. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) increased $670.5 million year-to-year primarily due to cash payments associated with our offshore Gulf of Mexico projects. Our cash outlays for asset purchases and business combinations were $326.6 million in 2005 versus $1.1 billion in 2004. The 2004 period includes $1 billion paid to El Paso in connection with the GulfTerra Merger.

Our investments in unconsolidated affiliates increased to $87.3 million in 2005 from $57.9 million in 2004. In 2005, we contributed $72 million to Deepwater Gateway, L.L.C. to fund our share of the repayment of its term loan. During 2004, we used $27.5 million to acquire additional ownership interests in K/D/S Promix LLC (Promix), which owns the Promix NGL fractionator, and contributed $24 million to Cameron Highway Oil Pipeline Company (Cameron Highway) for the construction of its crude oil pipeline.

Cash flows related to investing activities for 2005 also include (i) a $47.5 million cash receipt related to the partial return of our investment in Cameron Highway and (ii) a $42.1 million cash receipt from the sale of our investment in Starfish Pipeline Company, LLC (Starfish). The sale of our Starfish investment was required by the Federal Trade Commission (FTC) in order to gain its approval for the GulfTerra Merger.

For additional information related to our capital spending program, please read *Capital Spending* included within this Item 7.

Financing activities. Cash provided by financing activities was $533.9 million in 2005 compared to $917.6 million in 2004. We had net borrowings under our debt agreements of $169.8 million during 2005 versus $492.1 million during 2004. During 2005, the Operating Partnership issued an aggregate $1 billion in senior notes, the proceeds of which were used to temporarily reduce debt outstanding under its bank credit facilities, repay Senior Notes A and for general partnership purposes, including capital expenditures, asset purchases and business combinations. In addition, the Operating Partnership repaid the remaining $242.2 million that was outstanding at the end of 2004 under its 364-Day Acquisition Credit Facility using proceeds from Enterprise Products Partners' February 2005 equity offering. In addition, the Operating Partnership used the net proceeds from Enterprise Products Partners' November 2005 equity offering to temporarily reduce amounts outstanding under the Multi-Year Revolving Credit Facility.

In August 2005, the parent company borrowed $525 million under its credit facility to repay (i) $365 million owed by Enterprise Products GP to an affiliate of EPCO and (ii) $160 million of debt it assumed from EPCO as part of the contribution of net assets received from affiliates of EPCO. The parent company used the net proceeds from its initial public offering in August 2005 to reduce principal outstanding under this credit facility.

In September 2004, the Operating Partnership borrowed $2.8 billion under its bank credit facilities (principally the 364-Day Acquisition Credit Facility) to fund $655.3 million in cash payment obligations to El Paso in connection with the GulfTerra Merger; purchase $1.1 billion of GulfTerra s senior and senior subordinated notes in connection with tender offers; and repay $962 million outstanding under GulfTerra s revolving credit facility and secured term loans. Additionally, in September 2004, Enterprise Products GP borrowed $370 million from an affiliate of EPCO to purchase the 50% ownership interest in GulfTerra GP that was held by El Paso. In October 2004, the Operating Partnership issued an aggregate $2 billion in senior notes, the proceeds of which were used to reduce indebtedness outstanding under its bank credit facilities. Our consolidated repayments of debt during 2004 also reflect the use of $563.1 million of net proceeds from Enterprise Products Partners' May 2004 and August 2004 equity offerings to reduce indebtedness under the Operating Partnership s bank credit facilities.

Distributions paid to minority interests were $639.7 million during 2005 compared to $406.3 million during 2004. Distributions paid to minority interests primarily represent the distributions paid to the limited partners of Enterprise Products Partners (excluding the limited partner interests owned by the parent company). The increase in quarterly cash distributions paid by Enterprise Products Partners is primarily due to an increase in the number of its common units outstanding and its quarterly cash distribution rates. We expect that cash distributions paid to minority interests will increase in the future as a result of Enterprise Products Partners periodic issuance of common units.

Contributions from minority interests were $673.1 million during 2005 compared to $838.7 million during 2004. Contributions from minority interests primarily represent net cash proceeds received by Enterprise Products Partners in connection with its equity offerings (other than cash receipts from the parent company) and cash contributions from joint venture partners. Enterprise Products Partners issued 23,979,740 common units in 2005 to minority interest holders compared to 39,683,591 common units in 2004. Enterprise Products Partners received $612.6 million and $789.8 million from minority interest holders during 2005 and 2004, respectively, in connection with these sales of common units. In addition, Enterprise Products Partners received contributions from its joint venture partners of $39.1 million in 2005 compared to $9.6 million in 2004. These amounts relate to contributions from our joint venture partner in the Independence Hub project.

Our financing activities for 2004 include a net cash receipt of $19.4 million resulting from the settlement of forward starting interest rate swaps.

Comparison of Year Ended December 31, 2004 with Year Ended December 31, 2003

Operating activities. Net cash provided from operating activities was $388.4 million in 2004 compared to $426.7 million in 2003. The $38.3 million decrease in net cash provided from operating activities is primarily due to (i) net income adjusted for all non-cash items and the net effects of changes in operating accounts decreased $74.5 million year-to-year primarily due to timing of cash receipts from sales and cash payments for purchases and other expenses between periods and (ii) distributions received from unconsolidated affiliates increased $36.1 million year-to-year primarily due to distributions from GulfTerra GP, which we acquired in December 2003.

Investing activities. Cash used in investing activities was $1.3 billion in 2004 compared to $662.1 million in 2003. We used $1 billion in 2004 to complete the GulfTerra Merger, including our purchase of the South Texas midstream assets. Our expenditures for other asset purchases and business combinations were $1.1 billion in 2004 versus $37.3 million in 2003. Investments in unconsolidated affiliates were $57.9 million in 2004 compared to $463.9 million in 2003, which includes our $425 million cash payment to El Paso to acquire GulfTerra GP in December 2003. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) were essentially flat year-to-year at approximately $146 million for each period.

Financing activities. Cash provided by financing activities was $917.6 million in 2004 compared to $247.6 million in 2003. We had net borrowings of $492.1 million during 2004 compared to net repayments of $106.8 million during 2003. As discussed under *Financing activities* on page 71, net borrowings during 2004 primarily reflect debt transactions associated with the GulfTerra Merger. Our borrowing transactions during 2003 include the Operating Partnership s issuance of an aggregate $850 million in senior notes and the borrowing of $425 million under its bank credit facility to purchase GulfTerra GP. Repayments of debt during 2003 reflect the use of net proceeds from debt and equity offerings completed in 2003 to reduce indebtedness under the Operating Partnership s bank credit facilities, including the repayment of $1 billion outstanding under a term loan used to acquire ownership interests in the Mid-America Pipeline System and Seminole Pipeline.

Distributions paid to minority interests increased from $295.2 million during 2003 to $406.3 million in 2004 primarily due to an increase in Enterprise Products Partners' distribution-bearing units outstanding and higher cash distribution rates.

Contributions from minority interests were $838.7 million during 2004 compared to $667.9 million during 2003. Enterprise Products Partners issued 39,683,591 common units in 2004 to minority interest holders compared to 29,506,303 common units in 2003. Enterprise Products Partners received $789.8 million and $567.9 million from minority interest holders during 2004 and 2003, respectively, in connection with these sales of common units. In addition, Enterprise Products Partners received $100 million in 2003 from the sale of 4,413,549 Class B special units to an affiliate of EPCO classified as minority interest.

Financing activities include net cash receipts of $19.4 million in 2004 and $5.4 million in 2003 resulting from the settlement of interest rate hedging financial instruments.

CONTRACTUAL OBLIGATIONS

The following table summarizes our significant contractual obligations at December 31, 2005. A description of each type of contractual obligation follows (dollars in thousands).

	Payment or Settlement due by Period				
Contractual Obligations	**Total**	**Less than 1 year** (2006)	**1-3 years** (2007 2008)	**3-5 years** (2009 2010)	**More than 5 years** Beyond 2010
Scheduled Maturities of Long-Term Debt	$ 5,000,567		$ 517,000	$ 1,683,567	$ 2,800,000
Estimated Cash Payments for Interest	$ 3,186,486	$ 280,063	$ 535,743	$ 455,895	$ 1,914,785
Operating Lease Obligations	$ 179,623	$ 19,099	$ 33,848	$ 20,089	$ 106,587
Purchase Obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 1,518,016	$ 216,690	$ 433,973	$ 433,380	$ 433,973
NGLs	$ 6,095,907	$ 684,250	$ 1,118,948	$ 999,800	$ 3,292,909
Petrochemicals	$ 1,290,952	$ 1,079,110	$ 211,842		
Other	$ 87,162	$ 31,578	$ 44,724	$ 10,860	
Underlying major volume commitments:					
Natural gas (in BBtus)	127,850	18,250	36,550	36,500	36,550
NGLs (in MBbls)	63,130	9,251	12,827	10,172	30,880
Petrochemicals (in MBbls)	19,717	16,525	3,192		
Service payment commitments	$ 5,765	$ 5,037	$ 728		
Capital expenditure commitments	$ 208,575	$ 208,575			
Other Long-Term Liabilities, as reflected on our Consolidated Balance Sheet	$ 84,594		$ 24,828	$ 9,897	$ 49,869
Total dollar amount of obligations	$ 17,657,647	$ 2,524,402	$ 2,921,634	$ 3,613,488	$ 8,598,123

Scheduled Maturities of Long-Term Debt

We have long and short-term payment obligations under debt agreements such as indentures governing the Operating Partnership s senior notes and the credit agreements governing the Operating Partnership s Multi-Year Revolving Credit Facility and the parent company s credit facility. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. We have reclassified amounts due under the parent company s $525 Million Credit Facility to 2009 to reflect the parent company s refinancing of its long-term debt in

January 2006. For additional information regarding our debt obligations, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Estimated Cash Payments for Interest

We are obligated to make interest payments on our debt principal amounts outstanding. The amounts shown in the preceding table for estimated cash interest payments represent our forecast of variable and fixed interest payments to be made in connection with debt principal amounts outstanding at December 31, 2005 (including the effects of the parent company s refinancing of its long-term debt in

January 2006). Our estimates of future cash interest payments include the following amounts to be paid in connection with variable interest rates: $172.7 million in total, $40 million for 2006, $39.6 million for 2007, $39.3 million for 2008, $31.5 million for 2009 and $22.3 million for 2010. We estimated our variable interest rate cash payments by multiplying the weighted-average variable interest rate paid during 2005 (under each of our variable rate debt obligations that were outstanding at December 31, 2005) by the debt principal amount outstanding at that date and assumed that the balance outstanding would not change until maturity.

Our estimates of cash interest payments to be paid under fixed interest rate obligations were determined by multiplying the fixed interest rate associated with each fixed-rate obligation for each period that the principal would be outstanding until maturity. To the extent that we have exchanged a fixed interest rate for a variable interest rate, we have included the impact of such interest rate swap agreements in our calculations. Our internal estimates of long-term interest rates indicate that variable interest rates may exceed the fixed interest rates of the debt obligations underlying our interest rate swap agreements. If this occurs, we are responsible for payment of the excess of the current variable interest rate over the fixed interest rate of the underlying debt obligation. For conservatism, the amounts shown in the table above do not reflect any cash receipts from interest rate swap agreements (i.e. net reductions in cash outlays for interest) when the variable interest rate is less than the fixed interest rate of the underlying debt obligations.

For information regarding our interest rate swap agreements, please read Item 7A of this annual report.

Operating Lease Obligations

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated. For additional information regarding our operating lease commitments, please read Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Purchase Obligations

We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

Product purchase commitments. We have long and short-term product purchase obligations for NGLs, petrochemicals and natural gas with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2005 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

Service contract commitments. We have long and short-term commitments to pay third-party providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

Capital expenditure commitments. We have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with the capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. The preceding table shows these combined amounts for the periods indicated.

Other Long-Term Liabilities

We have recorded long-term liabilities on our balance sheet reflecting amounts we expect to pay in future periods beyond one year. These liabilities primarily relate to reserves for asset retirement obligations, environmental liabilities and other amounts. Amounts shown in the preceding table represent our best estimate as to the timing of payments based on available information.

OFF-BALANCE SHEET ARRANGEMENTS

Cameron Highway issued senior secured notes in December 2005. We secure a portion of these notes by (i) a pledge by us of our 50% partnership interest in Cameron Highway, (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of ours that serves as the operator of the Cameron Highway Oil Pipeline, and (iii) letters of credit in an initial amount of $18.4 million issued by the Operating Partnership on behalf of Cameron Highway. For more information regarding Cameron Highway s senior secured notes, please read Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005. We currently expect that Cameron Highway will seek to amend its senior secured notes during 2006 to address delayed increases in volumes due to disruptions of production caused by Hurricanes Katrina and Rita, but we believe that such amendments will be obtained without any material adverse effect on us.

Except for the foregoing, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably expected to have a material current or future effect on our financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

RECENT ACCOUNTING DEVELOPMENTS

The following information summarizes recently issued accounting guidance that will (or may) affect our financial statements in the future:

SFAS 123(R), *Share-Based Payment*, eliminates the ability to account for share-based compensation transactions using Accounting Principles Board (APB) 25 and generally requires that such transactions be accounted for using a fair value method. Historically, we have accounted for our share-based transactions using APB 25. We adopted SFAS 123(R) on January 1, 2006, which had a nominal effect on our financial statements. During 2006, we expect to record compensation expense of $7.1 million associated with the fair value method of accounting for profits interests and Enterprise Products Partners unit options and nonvested (or restricted) units using SFAS 123(R) based on awards outstanding at January 1, 2006.

SFAS 154, *Accounting Changes and Error Corrections*, provides guidance on the accounting for and reporting of accounting changes and error corrections. We adopted SFAS 154 on January 1, 2006.

Emerging Issues Task Force (EITF) 04-13, *Accounting for Purchases and Sale of Inventory With the Same Counterparty*, requires that two or more inventory transactions with the same counterparty be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. We are still evaluating this recent guidance, which is effective April 1, 2006 for our partnership, but we do not believe that our revenues or costs and expenses will be materially affected.

CRITICAL ACCOUNTING POLICIES

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset s cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts on a going forward basis. Some of these circumstances include changes in laws and regulations relating to restoration and abandonment requirements; changes in expected costs for dismantlement, restoration and abandonment as a result of changes, or expected changes, in labor, materials and other related costs associated with these activities; changes in the useful life of an asset based on the actual known life of similar assets, changes in technology, or other factors; and changes in expected salvage proceeds as a result of a change, or expected change in the salvage market.

At December 31, 2005 and 2004, the net book value of our property, plant and equipment was $8.7 billion and $7.8 billion, respectively. We recorded $328.7 million, $161 million and $101 million in depreciation expense during 2005, 2004 and 2003, respectively. A significant portion of the year-to-year increase in depreciation expense between 2005 and 2004 is attributable to the property, plant and equipment assets we acquired in the GulfTerra Merger in September 2004. For additional information regarding our property, plant and equipment, please read Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring recoverability of long-lived assets and equity method investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through future expected cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset s carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates. We recorded $1.2 million and $4.1 million for asset impairment charges in 2003 and 2004, respectively, related to NGL fractionation and storage facilities located in Mississippi.

Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value for the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee s industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates;

probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

Due to a deteriorating business environment, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in a non-cash impairment charge of $67.5 million. Since BEF was one of our equity investments at that time, our share of this loss was $22.5 million and was recorded as a component of equity earnings from unconsolidated affiliates during 2003.

For additional information regarding our asset impairment charges, please read Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with the GulfTerra Merger and related transactions. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities and other industry factors.

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline, etc.), (ii) any legal or regulatory developments that would impact such contractual rights, and (iii) any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. Additionally, if we determine that an intangible asset s unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2005 and 2004, the carrying value of our intangible asset portfolio was $913.6 million and $980.6 million, respectively. We recorded $88.9 million, $33.8 million and $14.8 million in amortization expense associated with our intangible assets during 2005, 2004 and 2003, respectively. A significant portion of the year-to-year increase in amortization expense between 2005 and 2004 is attributable to the intangible assets we acquired in the GulfTerra Merger.

For additional information regarding our intangible assets, please read Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Methods we employ to measure the fair value of goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values and is primarily comprised of $387.1 million associated with the GulfTerra Merger. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit s fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management s estimates of operating margins and transportation volumes, (ii) long-term growth rates for cash flows beyond the discrete forecast period, and (iii) appropriate discount rates. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2005 and 2004, the carrying value of our goodwill was $494 million and $459.2 million, respectively.

For additional information regarding our goodwill, please read Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer s price is fixed or determinable and (iv) collectibility is reasonably assured. When sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we record any necessary allowance for doubtful accounts.

Our use of certain estimates for revenues and operating costs and other expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the timing of compiling actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for the subject period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month. If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods.

Reserves for environmental matters

Each of our business segments is subject to federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain circumstances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves.

At December 31, 2005 and 2004, we had a liability for environmental remediation of $21 million, which was derived from a range of reasonable estimates based upon studies and site surveys. In accordance with SFAS 5 "*Accounting for Contingencies*" and Financial Accounting Standards Board

Interpretation (FIN) 14, "*Reasonable Estimation of the Amount of a Loss*," we recorded our best estimate of these remediation activities.

Natural gas imbalances

Natural gas imbalances result when customers physically deliver a larger or smaller quantity of natural gas into our pipelines than they take out. In general, we value such imbalances using a twelve-month moving average of natural gas prices, which we believe is reasonable given that the actual settlement dates for such imbalances are generally not known. As a result, significant changes in natural gas prices between reporting periods may impact our estimates.

At December 31, 2005 and 2004, our imbalance receivables were $89.4 million and $56.7 million, respectively, and are reflected as a component of accounts receivable. At December 31, 2005 and 2004, our imbalance payables were $80.5 million and $59 million, respectively, and are reflected as a component of accrued gas payables.

SUMMARY OF RELATED PARTY TRANSACTIONS

In accordance with SFAS 57, *Related Party Disclosures,* we have identified our material related party revenues and costs and expenses. The following table summarizes our related party transactions (including those of our predecessor, Enterprise Products GP) for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2005	**2004**	**2003**
Revenues from consolidated operations			
EPCO and affiliates	$ 311	$ 2,697	$ 4,241
Shell		542,912	293,109
Unconsolidated affiliates	354,461	258,541	266,894
Total	$ 354,772	$ 804,150	$ 564,244
Operating costs and expenses			
EPCO and affiliates	$ 293,134	$ 203,100	$ 149,915
Shell		725,420	607,277
Unconsolidated affiliates	23,563	37,587	43,752
Total	$ 316,697	$ 966,107	$ 800,944
General and administrative expenses			
EPCO and affiliates	$ 41,054	$ 29,307	$ 28,716
Interest Expense			
EPCO and affiliates	$ 15,306	$ 5,849	

For additional information regarding our related party transactions identified in accordance with GAAP, please read Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding certain business relationships and related transactions, please read Item 13 of this annual report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities.

Historically, Shell was considered a related party under GAAP because it owned more than 10% of the limited partner interests of Enterprise Products Partners and, prior to 2003, held a 30% membership interest in Enterprise Products GP. As a result of Shell selling a portion of its limited partner interests in Enterprise Products Partners to third parties and the issuance of additional common units by Enterprise Products Partners, Shell owned less than 10% of Enterprise Products Partners common units at the beginning of 2005. Shell sold its 30% interest in Enterprise Products GP to an affiliate of EPCO in September 2003. As a result of Shell's reduced equity interest in Enterprise Products Partners and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party under GAAP in January 2005.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments to Promix for NGL transportation, storage and fractionation services.

OTHER ITEMS

Non-GAAP reconciliation

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows (dollars in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Total non-GAAP gross operating margin	$ 1,136,347	$ 655,191	$ 410,414
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:			
Depreciation and amortization in operating costs and expenses	(413,441)	(193,734)	(115,642)
Retained lease expense, net in operating costs and expenses	(2,112)	(7,705)	(9,094)
Gain on sale of assets in operating costs and expenses	4,488	15,901	16
General and administrative costs	(64,194)	(47,264)	(39,164)
GAAP consolidated operating income	661,088	422,389	246,530
Other net expense, primarily interest expense	(243,581)	(159,459)	(134,297)
GAAP income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 417,507	$ 262,930	$ 112,233

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the retained leases). These subleases were acquired from EPCO by Enterprise Products Partners in 1998, and are part of the administrative services agreement. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. Enterprise Products Partners records the full value of such lease payments made by EPCO as a non-cash related party operating expense. Apart from the common units EPCO received from Enterprise Products Partners in 1998, EPCO does not receive any additional ownership rights in us as a result of payments it makes in connection with the retained leases. For additional information regarding the administrative services agreement and the retained leases, please read Item 13 of this annual report.

Cumulative effect of changes in accounting principles

Our Statements of Consolidated Operations and Comprehensive Income reflect the following cumulative effects of changes in accounting principles:

In 2005, we recorded a $4.2 million non-cash expense related to certain asset retirement obligations due to our implementation of FIN 47 as of December 31, 2005, of which $0.2 million is presented as the cumulative effect of a change in accounting principle for the parent company. The remaining $4 million is a component of minority interest expense since the limited partners of Enterprise Products Partners (other than the parent company) were allocated their share of this charge.

In 2004, we changed the method a subsidiary used to account for its planned major maintenance activities and the method we used to account for our investment in VESCO. These changes resulted in a combined $10.8 million non-cash gain in 2004, of which $0.2 million is presented as the cumulative effect of a change in accounting principle for the parent company. The remaining $10.6 million non-cash gain is a component of minority interest expense.

For additional information regarding these changes in accounting principles, including a presentation of the pro forma effects these changes would have had on our historical earnings, please read Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Financial statement reclassifications

Certain reclassifications have been made to the prior year s financial statements to conform to the current year presentation. During 2005, we changed the classification of changes in restricted cash in our Statements of Consolidated Cash Flows to present such changes as an investing activity. We previously presented such changes as an operating activity. In the accompanying Statements of Consolidated Cash Flows for the years ended December 31, 2004 and 2003, we reclassified the change in restricted cash to be consistent with our 2005 presentation. This reclassification resulted in a $12.3 million and $5.1 million increase to cash flows used in investing activities and a corresponding increase to cash provided by operating activities from the amounts previously presented for the years ended December 31, 2004 and 2003, respectively.

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

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings, fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument s gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. For additional information regarding our accounting for financial instruments, please read Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

Enterprise Products Partners routinely reviews its outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates; thus, Enterprise Products Partners may realize income or loss depending on the specific exposure. When this occurs, Enterprise Products Partners may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. EPE Holdings and Enterprise Products GP oversee the strategies associated with these financial risks and approve instruments that are appropriate for our requirements.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business environment.

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2005 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	**Number Of Swaps**	**Period Covered by Swap**	**Termination Date of Swap**	**Fixed to Variable Rate** (1)	**Notional Amount**
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 7.26%	$ 50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.8%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 5.24%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 4.99%	$200 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest e xpense.

These eleven agreements have a combined notional amount of $1.1 billion and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month London interbank offered rate (LIBOR) (plus an applicable margin as defined in each swap agreement), and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the settlement period). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

The total fair value of these eleven interest rate swaps at December 31, 2005, was a liability of $19.2 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2005 and 2004 reflects a $10.8 million and $9.1 million benefit from these swap agreements, respectively.

82

The following tables show the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in thousands). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic reset rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

Scenario	Resulting Classification	Swap Fair Value at December 31, 2004	December 31, 2005	February 1, 2006
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 505	$ (19,179)	$ (28,621)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(31,586)	(50,308)	(59,744)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	32,596	11,950	2,503

The fair value of the interest rate swaps excludes the benefit we have already recorded in earnings. The change in fair value between December 31, 2005 and February 1, 2006 is primarily due to an increase in market interest rates relative to the forward interest rate curve used to determine the fair value of our financial instruments. The underlying floating LIBOR forward interest rate curve used to determine the February 1, 2006 fair values ranged from approximately 4.3% to 5.2% using 6-month reset periods ranging from October 2005 to October 2014.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with natural gas and NGLs, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas or NGLs. The commodity financial instruments we utilize may be settled in cash or with another financial instrument. Historically, we have not hedged our exposure to risks associated with petrochemical products, including MTBE.

We have adopted a policy to govern our use of commodity financial instruments. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise Products GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise Products GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

At December 31, 2005, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of economic hedges. The fair value of our commodity financial instrument portfolio at December 31, 2005 was a liability of $0.1 million. We recorded nominal amounts of earnings from such commodity financial instruments during 2005, 2004 and 2003.

Product Purchase Commitments

We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, please read *Contractual Obligations* included under Item 7 of this annual report.

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

ENTERPRISE GP HOLDINGS L.P.

INDEX TO FINANCIAL STATEMENTS

	Page No.
Report of Independent Registered Public Accounting Firm	86
Consolidated Balance Sheets as of December 31, 2005 and 2004	87
Statements of Consolidated Operations and Comprehensive Income for the Years Ended December 31, 2005, 2004 and 2003	88
Statements of Consolidated Cash Flows for the Years Ended December 31, 2005, 2004 and 2003	89
Statements of Consolidated Partners' Equity for the Years Ended December 31, 2005, 2004 and 2003	90
Notes to Consolidated Financial Statements	
Note 1 Partnership Organization	91
Note 2 Summary of Significant Accounting Policies	96
Note 3 Recent Accounting Developments	103
Note 4 Revenue Recognition	104
Note 5 Accounting for Equity Awards	106
Note 6 Employee Benefit Plans	108
Note 7 Financial Instruments	109
Note 8 Cumulative Effect of Changes in Accounting Principles	113
Note 9 Inventories	115
Note 10 Property, Plant and Equipment	116
Note 11 Investments in and Advances to Unconsolidated Affiliates	118
Note 12 Business Combinations and Other Acquisitions	124
Note 13 Intangible Assets and Goodwill	130
Note 14 Debt Obligations	133
Note 15 Partners Equity	139
Note 16 Distributions to Partners	140
Note 17 Business Segments	141
Note 18 Related Party Transactions	145
Note 19 Provision for Income Taxes for Certain Pipeline Operations	152
Note 20 Earnings per Unit	153
Note 21 Commitments and Contingencies	154
Note 22 Significant Risks and Uncertainties	158
Note 23 Supplemental Cash Flow Information	160
Note 24 Selected Quarterly Data (Unaudited)	161
Note 25 Condensed Financial Information of Operating Partnership	161
Note 26 Subsequent Events	162

85

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of EPE Holdings, LLC and

Unitholders of Enterprise GP Holdings L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise GP Holdings L.P. and subsidiaries (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of consolidated operations and comprehensive income, consolidated cash flows and consolidated partners equity for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in Item 15. These financial statements and financial statement schedule are the responsibility of Enterprise GP Holdings management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. The Company is not required to have, nor were we engaged to perform, an audit of its 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise GP Holdings L.P. and subsidiaries at December 31, 2005 and 2004, and the results of their operations and their 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 of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 27, 2006

ENTERPRISE GP HOLDINGS L.P.

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31,	
ASSETS	**2005**	**2004**
Current assets		
Cash and cash equivalents	$ 42,650	$ 25,006
Restricted cash	14,952	26,157
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $25,849 at December 31, 2005 and $24,310 at December 31, 2004	1,448,026	1,058,375
Accounts receivable - related parties	3,077	25,151
Inventories	339,606	189,019
Prepaid and other current assets	120,308	80,893
Assets held for sale		36,562
Total current assets	1,968,619	1,441,163
Property, plant and equipment, net	8,689,024	7,831,467
Investments in and advances to unconsolidated affiliates	471,921	519,164
Intangible assets, net of accumulated amortization of $163,121 at December 31, 2005 and $74,183 at December 31, 2004	913,626	980,601
Goodwill	494,033	459,198
Deferred tax asset	3,606	6,467
Other assets	47,359	77,841
Total assets	$ 12,588,188	$ 11,315,901
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Current maturities of debt		$ 18,450
Accounts payable - trade	$ 266,771	203,144
Accounts payable - related parties	24,310	41,293
Accrued gas payables	1,372,837	1,021,294
Accrued expenses	30,294	130,051
Accrued interest	71,286	73,151
Other current liabilities	127,473	104,979
Total current liabilities	1,892,971	1,592,362
Long-term debt	4,968,280	4,629,219
Other long-term liabilities	84,594	63,739
Minority interest	4,927,037	4,956,543
Commitments and contingencies		
Partners' equity		
Limited partner units (88,884,116 units outstanding at December 31, 2005 and 74,667,332 units outstanding at December 31, 2004)	696,223	49,478
General partner	11	6
Accumulated other comprehensive income	19,072	24,554
Total partners' equity	715,306	74,038
Total liabilities and partners' equity	$ 12,588,188	$ 11,315,901

See Notes to Consolidated Financial Statements

ENTERPRISE GP HOLDINGS L.P.

STATEMENTS OF CONSOLIDATED OPERATIONS

AND COMPREHENSIVE INCOME

(Dollars in thousands, except per unit amounts)

	For Year Ended December 31, 2005	2004	2003
REVENUES			
Third parties	$11,902,187	$ 7,517,052	$ 4,782,187
Related parties	354,772	804,150	564,244
Total	12,256,959	8,321,202	5,346,431
COST AND EXPENSES			
Operating costs and expenses			
Third parties	11,229,528	6,938,229	4,245,833
Related parties	316,697	966,107	800,944
Total operating costs and expenses	11,546,225	7,904,336	5,046,777
General and administrative costs			
Third parties	23,140	17,957	10,448
Related parties	41,054	29,307	28,716
Total general and administrative costs	64,194	47,264	39,164
Total costs and expenses	11,610,419	7,951,600	5,085,941
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	14,548	52,787	(13,960)
OPERATING INCOME	661,088	422,389	246,530
OTHER INCOME (EXPENSE)			
Interest expense	(233,696)	(155,740)	(140,806)
Dividend income from unconsolidated affiliates			5,595
Interest expense related parties	(15,306)	(5,849)	
Other, net	5,421	2,130	914
Other expense	(243,581)	(159,459)	(134,297)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	417,507	262,930	112,233
Provision for income taxes	(8,362)	(3,761)	(5,293)
INCOME BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	409,145	259,169	106,940
Minority interest	(353,642)	(229,607)	(91,079)
INCOME BEFORE CHANGES IN ACCOUNTING PRINCIPLES	55,503	29,562	15,861
Cumulative effect of changes in accounting principles (see Note 8)	(227)	216	
NET INCOME	$ 55,276	$ 29,778	$ 15,861
Cash flow financing hedges		19,405	5,354
Amortization of cash flow financing hedges	(4,048)	(1,275)	3,196
Change in fair value of commodity hedges	(1,434)	1,434	
COMPREHENSIVE INCOME	$ 49,794	$ 49,342	$ 24,411
ALLOCATION OF NET INCOME TO: (see Note 16)			
Limited partners' interest in net income	$ 55,270	$ 29,775	$ 15,859
General partner interest in net income	$ 6	$ 3	$ 2
EARNING PER UNIT: (see Note 20)			
Basic income per unit before changes in accounting principles	$ 0.70	$ 0.40	$ 0.21
Basic income per unit	$ 0.69	$ 0.40	$ 0.21
Diluted income per unit before changes in accounting principles	$ 0.70	$ 0.40	$ 0.21
Diluted income per unit	$ 0.69	$ 0.40	$ 0.21

See Notes to Consolidated Financial Statements

88

ENTERPRISE GP HOLDINGS L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in thousands)

	For Year Ended December 31,		
	2005	**2004**	**2003**
OPERATING ACTIVITIES			
Net income	$ 55,276	$ 29,778	$ 15,861
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation and amortization in operating costs and expenses	413,441	193,734	115,642
Depreciation and amortization in general and administrative costs	7,241	1,650	159
Amortization in interest expense	152	3,503	12,634
Equity in (income) loss of unconsolidated affiliates	(14,548)	(52,787)	13,960
Distributions received from unconsolidated affiliates	56,058	68,027	31,882
Provision for impairment of long-lived asset		4,114	1,200
Cumulative effect of changes in accounting principles	227	(216)	
Operating lease expense paid by EPCO, Inc.	2,112	7,705	9,094
Other expenses paid by EPCO, Inc.			443
Minority interest	353,642	229,607	91,079
Gain on sale of assets	(4,488)	(15,901)	(16)
Deferred income tax expense	8,594	9,608	10,534
Changes in fair market value of financial instruments	122	5	(29)
Net effect of changes in operating accounts (see Note 23)	(263,728)	(90,454)	124,263
Net cash provided from operating activities	614,101	388,373	426,706
INVESTING ACTIVITIES			
Capital expenditures	(864,453)	(155,793)	(146,790)
Contributions in aid of construction costs	47,004	8,865	877
Proceeds from sale of assets	44,746	6,882	212
Decrease (increase) in restricted cash	11,205	(12,305)	(5,100)
Cash used for business combinations and asset purchases (see Note 12)	(326,602)	(1,094,661)	(37,348)
Acquisition of intangible asset	(1,750)		(2,000)
Investments in unconsolidated affiliates	(87,342)	(57,948)	(463,876)
Advances to unconsolidated affiliates	(702)	(6,464)	(8,051)
Return of investment from unconsolidated affiliate	47,500		
Cash used in investing activities	(1,130,394)	(1,311,424)	(662,076)
FINANCING ACTIVITIES			
Borrowings under debt agreements	4,723,345	6,304,505	1,926,210
Repayments of debt	(4,553,568)	(5,812,445)	(2,033,000)
Debt issuance costs	(9,297)	(19,911)	(8,833)
Distributions paid to partners	(32,942)	(16,430)	(16,765)
Distributions paid to minority interests	(639,698)	(406,259)	(295,201)
Contributions from minority interests	673,097	838,718	667,945
Contributions from partners		1,614	1,200
Net proceeds from issuance of units in initial public offering	373,000		
Treasury units reissued		8,394	646
Settlement of cash flow financing hedges		19,405	5,354
Cash provided by financing activities	533,937	917,591	247,556
NET CHANGE IN CASH AND CASH EQUIVALENTS	17,644	(5,460)	12,186
CASH AND CASH EQUIVALENTS, JANUARY 1	25,006	30,466	18,280
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 42,650	$ 25,006	$ 30,466

See Notes to Consolidated Financial Statements

ENTERPRISE GP HOLDINGS L.P.

STATEMENTS OF CONSOLIDATED PARTNERS EQUITY

(See Note 15 for Unit History and Detail of Changes in Limited Partners Equity)

(Dollars in thousands)

	Limited Partners	General Partner	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2002	$ 20,545	$ 2	$ (3,560)	$ 16,987
Net income	15,859	2		15,861
Distributions to partners	(16,764)	(1)		(16,765)
Operating leases paid by EPCO, Inc.	141			141
Other expenses paid by EPCO, Inc.	6			6
Contributions from partners	11,666	1		11,667
Treasury lock financial instruments recorded as cash flow hedges:				
- Reclassification of change in fair value			3,560	3,560
- Cash gains on settlement			5,354	5,354
- Amortization of gain as component of interest expense			(364)	(364)
- Other	(4)			(4)
Balance, December 31, 2003	31,449	4	4,990	36,443
Net income	29,775	3		29,778
Distributions to partners	(16,429)	(1)		(16,430)
Operating leases paid by EPCO, Inc.	152			152
Other expenses paid by EPCO, Inc.	2,906			2,906
Contributions from partners	1,614			1,614
Change in fair value of financial instruments			1,434	1,434
Interest rate hedging financial instruments recorded as cash flow hedges:				
- Cash gains on settlement			19,405	19,405
- Amortization of gain as component of interest expense			(1,275)	(1,275)
Other	11			11
Balance, December 31, 2004	49,478	6	24,554	74,038
Net income	55,270	6		55,276
Distributions to partners	(32,941)	(1)		(32,942)
Operating leases paid by EPCO, Inc.	72			72
Net proceeds from initial public offering	373,000			373,000
Acquisition of minority interest from El Paso	90,845			90,845
Contribution of net assets from sponsor affiliates in connection with initial public offering	160,604			160,604
Amortization of equity-related awards	75			75
Change in fair value of financial instruments			(1,434)	(1,434)
Interest rate hedging financial instruments recorded as cash flow hedges:				
- Amortization of gain as component of interest expense			(4,048)	(4,048)
Other	(180)			(180)
Balance, December 31, 2005	$ 696,223	$ 11	$ 19,072	$ 715,306

See Notes to Consolidated Financial Statements

ENTERPRISE GP HOLDINGS L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Partnership Organization and Basis of Financial Statement Presentation

Partnership organization and formation

Enterprise GP Holdings L.P. is a publicly traded Delaware limited partnership the units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPE. Enterprise GP Holdings L.P. was formed in April 2005 and completed its initial public offering of 14,216,784 units in August 2005. For information regarding the initial public offering of Enterprise GP Holdings L.P., see Note 15.

Significant Relationships referenced in Notes to Consolidated Financial Statements

Unless the context requires otherwise, references to *we*, *us*, *our* or *Enterprise GP Holdings L.P.* are intended to mean and include the business and operations of Enterprise GP Holdings L.P., the parent company, as well as its consolidated subsidiaries, which include Enterprise Products GP, LLC and Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to *the parent company* are intended to mean and include Enterprise GP Holdings L.P., individually as the parent company, and not on a consolidated basis.

References to *EPE Holdings* mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings L.P.

References to *Enterprise Products Partners* mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to *Enterprise Products GP* mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners L.P.

References to *EPCO* mean EPCO, Inc., which is a related party affiliate to all of the foregoing named entities.

Business of Enterprise GP Holdings

Enterprise GP Holdings L.P. is the sole member of Enterprise Products GP, which is the general partner of Enterprise Products Partners. The primary business purpose of Enterprise Products GP is to manage the affairs and operations of Enterprise Products Partners, a North American energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), and crude oil, and an industry leader in the development of pipeline and other midstream infrastructure in the continental United States and Gulf of Mexico. Enterprise Products Partners conducts substantially all of its business through a wholly owned subsidiary, Enterprise Products Operating L.P. (the Operating Partnership).

Enterprise GP Holdings L.P. is owned 99.99% by its limited partners and 0.01% by EPE Holdings, its general partner. Enterprise GP Holdings L.P., EPE Holdings, Enterprise Products GP and Enterprise Products Partners are under common control of Dan L. Duncan, the Chairman and the controlling shareholder of EPCO. Enterprise GP Holdings L.P. and Enterprise Products GP have no independent operations outside those of Enterprise Products Partners.

In September 2004, we completed the GulfTerra Merger transactions, whereby, among other transactions, GulfTerra Energy Partners, L.P. (GulfTerra) merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra s general partner (GulfTerra GP) became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso Corporation (El Paso) that are located in South Texas (the STMA acquisition).

Contributions made by affiliates of EPCO in August 2005 in connection with the initial public offering of Enterprise GP Holdings L.P.

In connection with the initial public offering of the parent company, affiliates of EPCO contributed certain ownership interests in Enterprise Products Partners to the parent company consisting of (i) 13,454,498 common units of Enterprise Products Partners acquired from an affiliate of El Paso in January 2005 and (ii) a 100% ownership interest in Enterprise Products GP. Concurrent with the contribution of these ownership interests, the parent company assumed $160 million of debt and $0.5 million of accrued interest from EPCO.

In accordance with Statement of Financial Accounting Standard (SFAS) 141, the transfer of such net assets from affiliates of EPCO to the parent company was recorded at the transferors net historical carrying amounts of $160.6 million since both the transferors and transferee are under common control of EPCO. As consideration for these transfers, affiliates of EPCO received 74,667,332 units (the sponsor units) of Enterprise GP Holdings L.P.

Basis of presentation of consolidated financial statements

In accordance with generally accepted accounting principles, the transfer of net assets to the parent company from affiliates of EPCO in August 2005 was accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests. As a result, the historical consolidated financial information of Enterprise GP Holdings L.P. presented in this annual report on Form 10-K for periods prior to its receipt of such contributions from EPCO has been presented using the consolidated financial information of Enterprise Products GP, which has been deemed the predecessor company of Enterprise GP Holdings L.P.

The presentation of such predecessor consolidated financial statements assumes that (i) the historical ownership interest in Enterprise Products GP held by El Paso (during the fourth quarter of 2004 and a portion of January 2005) was a third-party minority ownership interest in the net assets of such subsidiary and (ii) the historical ownership interests in Enterprise Products GP held by affiliates of EPCO (prior to the contribution of net assets from EPCO in August 2005) were owned by the parent company. This method of presentation is substantially on the same basis that our consolidated results of operations and financial condition have been presented since the contribution of net assets from EPCO.

Since the parent company owns the general partner of Enterprise Products Partners, it controls the activities of Enterprise Products GP and Enterprise Products Partners. As a result, the parent company consolidates the financial information of these subsidiaries with that of its own. We refer to the consolidated group of entities as Enterprise GP Holdings L.P.

The amount of net earnings of Enterprise Products Partners allocated to its limited partner interests not owned by the parent company is reflected as minority interest expense in our consolidated results of operations. Likewise, the amount of net assets of Enterprise Products Partners allocated to its limited partner interests not owned by the parent company is reflected as minority interest in our consolidated balance sheet. Apart from such minority interest-related amounts, debt and interest expense recognized in connection with the parent company s borrowings, our consolidated financial statements do not differ materially from those of Enterprise Products Partners.

Parent company financial information

The parent company has no separate operating activities apart from those conducted by the Operating Partnership (see Note 25). The principal sources of cash flow for the parent company are its investments in limited and general partner ownership interests in Enterprise Products Partners. The parent company s primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The parent company s assets and liabilities are not available to satisfy the debts and other obligations of Enterprise Products Partners.

In order to fully understand the financial condition and results of operations of the parent company, we are providing the financial information of Enterprise GP Holdings L.P. apart from that of our consolidated partnership information included within this Item 8. The following financial statements reflect the transactions of the parent company since its formation in April 2005.

The following table presents the parent company's balance sheet data at December 31, 2005:

ASSETS	
Current assets	$ 608
Investments in unconsolidated affiliates [1]	834,837
Total assets	$ 835,445
LIABILITIES AND PARTNERS' EQUITY	
Current liabilities[2]	$ 4,704
Long-term debt [3]	134,500
Partners equity[4]	696,241
Total liabilities and partners equity	$ 835,445

(1) Represents the parent company s equity-method investments in Enterprise Products GP and Enterprise Products Partners. These parent company investments are eliminated in the process of consolidating the financial statements of the parent company with those of Enterprise Products GP and Enterprise Products Partners.

(2) Represents current payable amounts primarily related to accrued initial public offering expenses and interest.

(3) Represents borrowings outstanding under the parent company s $525 Million Credit Facility. For additional information regarding the parent company s debt obligation, see Note 14.

(4) Represents partner capital accounts recorded under generally accepted accounting principles including $373 million in net proceeds resulting from the parent company s initial public offering in August 2005.

The following table presents the parent company s statement of operations since its formation in April 2005.

Equity in income of unconsolidated affiliates [1]	$	24,507
General and administrative costs[2]	461	
Operating income	24,046	
Other income (expense)		
Interest expense [3]	(3,445)	
Interest income	30	
Net income	$	20,631

(1) Represents the parent company s earnings from its equity-method investments in Enterprise Products GP and Enterprise Products Partners. The parent company obtained these investments as a result of net asset contributions from affiliates of EPCO that were made in connection with the initial public offering of the parent company in August 2005; therefore, the equity earnings shown are for the period since the assets were contributed.

(2) Represents the parent company s general and administrative costs since late August 2005.

(3) Primarily represents interest expense associated with the parent company s $525 Million Credit Facility.

The following table shows the parent company s statement of cash flow since its formation in April 2005.

Operating activities	
Net income	$ 20,631
Adjustments to reconcile net income to cash flows used in operating activities:	
Equity in income of unconsolidated affiliates	(24,507)
Distributions from unconsolidated affiliates [1]	27,160
Amortization of equity related awards	21
Net effect of changes in operating accounts	4,584
Cash provided by operating activities	27,889
Investing activities	
Investments in unconsolidated affiliates [2]	(366,458)
Cash used in investing activities	(366,458)
Financing activities	
Borrowings under debt agreements [3]	531,000
Repayments of debt [4]	(556,746)
Contribution from general partner	1
Proceeds from issuance of units in initial public offering[5]	373,000
Distributions paid to partners[6]	(8,178)
Cash provided by financing activities	339,077
Net change in cash and cash equivalents	508
Cash and cash equivalents, at formation	
Cash and cash equivalents, end of period	$ 508

(1) Represents distributions received by the parent company from its equity-method investments in Enterprise Products GP and Enterprise Products Partners.

(2) Represents the cash contribution made by the parent company to Enterprise Products GP in August 2005. Enterprise Products GP used this contribution to repay indebtedness owed to an affiliate of EPCO.

(3) Primarily represents borrowings by the parent company under its $525 Million Credit Facility to repay (i) $365 million of indebtedness owed by Enterprise Products GP to an affiliate of EPCO and (ii) $160.5 million of debt assumed by the parent company from EPCO in August 2005.

(4) Primarily represents repayment of (i) $160.5 million of debt assumed from affiliates of EPCO and (ii) $373 million that was borrowed by the parent company under its $525 Million Credit Facility in August 2005. The $373 million was repaid using proceeds from the parent company s initial public offering.

(5) Represents net proceeds from the parent company s initial public offering in August 2005.

(6) Represents the prorated distributions paid to partners in November 2005 with respect to the third quarter of 2005.

2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts amount is generally determined based on specific identification and estimates of future uncollectible accounts. Our procedure for recording an allowance for doubtful accounts is based on (i) our historical experience, (ii) the financial stability of our customers and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. We routinely review our estimates in this area to ascertain that we have recorded sufficient reserves to cover potential losses. Our allowance for doubtful accounts was $25.8 million and $24.3 million at December 31, 2005 and 2004, respectively.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase. Our Statements of Consolidated Cash Flows are prepared using the indirect method.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material intercompany accounts and transactions. We consolidate majority-owned subsidiaries in which we possess a controlling financial interest through a direct or indirect ownership of a majority voting interest in the subsidiary.

Investments in which we own 3% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. If the investee is organized as a limited liability company and maintains separate ownership accounts for its members, we account for our investment using the equity method if our ownership interest is between 3% and 50%. For all other types of investees, we apply the equity method of accounting if our ownership interest is between 20% and 50%. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts are material and remain on our or our equity method investees balance sheet in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to Enterprise GP Holdings L.P. but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Deferred Revenues

We recognize revenues when earned. Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. Please see Note 4 for additional discussion of revenues.

Dollar Amounts

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Earnings Per Unit

Earnings per unit is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 20 for our computation of earnings per unit for 2005, 2004 and 2003.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management s estimate of the ultimate cost to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred. Expenditures to mitigate or prevent future environmental contamination are capitalized.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability estimated at $21 million for remediation costs associated with mercury gas meters. This estimate is included in other long-term liabilities on our Consolidated Balance Sheets at December 31, 2005 and 2004.

Costs of environmental compliance and monitoring aggregated $3.3 million, $1.9 million and $1.6 million during 2005, 2004 and 2003, respectively.

Equity Awards

Beginning January 1, 2006, we will account for our equity awards using the provisions of SFAS 123(R), *Share-Based Payment.* Historically, the equity awards were accounted for using the intrinsic value method described in Accounting Principles Board Opinion (APB) 25, *Accounting for Stock Issued to Employees.* SFAS 123(R) requires us to recognize compensation expense related to the equity awards based on the fair value of the award at the grant date. The fair value of an equity award will be determined using option pricing models (Black-Scholes or Binomial models). Under SFAS 123(R), the fair value of an award will be amortized to earnings on a straight-line basis over the requisite service or vesting period. Previously recognized deferred compensation related to Enterprise Products Partners nonvested units will be reversed on January 1, 2006. At December 31, 2005, our equity awards related solely to Enterprise Products Partners. The parent company had not issued any such awards.

Unit options. Under APB 25, we did not recognize any compensation expense related to unit options of Enterprise Products Partners when the exercise price was equal to or greater than the market price of the underlying equity on the date of grant. Based on information currently available, we estimate that the compensation expense related to Enterprise Products Partners unit options will be approximately $0.6 million in 2006 using the provisions of SFAS 123(R).

Profits Interests. In connection with the initial public offering of the parent company in August 2005, EPE Unit L.P. (the Employee Partnership) was formed to allow certain employees of EPCO to increase their ownership in the parent company and to serve as an incentive arrangement for such employees through a profits interest in the Employee Partnership. During 2005, the value of the profits interests was accounted for similar to a stock appreciation right. Based on information currently available, we estimate that the share of compensation expense related to the profits interests will be approximately $2.3 million in 2006 using the provisions of SFAS 123(R). Using a Black-Scholes model, EPCO estimated the grant date fair value of the Class B partnership interests to be $12.5 million. For additional information regarding the Employee Partnership, see *Relationship with EPCO and affiliates* under Note 18.

Nonvested Units. Enterprise Products Partners issued nonvested (or restricted) units to key employees of EPCO during 2005 and 2004. In general, Enterprise Products Partners nonvested common units are classified as either time-vested or performance-based. Historically, unearned compensation, representing the fair market value of such nonvested units at the date of issuance, was charged to earnings as compensation expense on a straight-line basis over the vesting period. Prior to 2006, we recognized forfeitures of Enterprise Products Partners nonvested units as they occurred. As a result of SFAS 123(R), we will estimate such forfeitures at grant date. Based on information currently available, we estimate that our compensation expense related to Enterprise Products Partners nonvested units will be $4.2 million in 2006 using the provisions of SFAS 123(R).

Pro forma disclosures under SFAS 123. In accordance with SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure, we disclose the pro forma effect on our earnings as if the fair value method of SFAS 123, Accounting for Stock-Based Compensation had been used instead of the intrinsic-value method of APB 25 to account for the aforementioned equity awards. The effects of applying SFAS 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. No pro forma adjustment is required for Enterprise Products Partners nonvested units since compensation expense was recognized in 2005 and 2004 based on estimated fair values of the awards.

The fair value of each unit option to purchase Enterprise Products Partners common units is estimated on the date of grant using the Black-Scholes option pricing model and various assumptions. For those unit options granted during 2005, we used the following assumptions: (i) expected life of options of seven years; (ii) risk-free interest rate of 4.2%, (iii) expected distribution yield on common units of Enterprise Products Partners of 9.2% and (iv) expected unit price volatility on Enterprise Products Partners common units of 20%.

The fair value of the Employee Partnership Class B partnership equity awards was also estimated on the date of grant using the Black-Scholes option pricing model and various assumptions. We used the following assumptions to estimate the fair value of these equity awards: (i) expected life of award of five years; (ii) risk-free interest rate of 4.1%; (iii) expected distribution yield on units of Enterprise GP Holdings L.P. of 3% and (iv) expected unit price volatility of Enterprise GP Holdings L.P. s units of 30%.

The following table shows the pro forma effects for the periods indicated.

	For Year Ended December 31,		
	2005	**2004**	**2003**
Reported net income	$ 55,276	$ 29,778	$ 15,861
Additional unit option-based compensation			
expense estimated using fair value-based method	(38)	(19)	(14)
Reduction in compensation expense related to			
Employee Partnership equity awards	82		
Pro forma net income	55,320	29,759	15,847
Multiplied by general partner ownership interest	0.01%	0.01%	0.00%
General partner interest in pro forma net income	$ 6	$ 3	$ -
Pro forma net income	$ 55,320	$ 29,759	$ 15,847
Less general partner interest in pro forma net income	(6)	(3)	
Pro forma net income available to limited partners	$ 55,314	$ 29,756	$ 15,847
Basic and diluted earnings per unit, net of general partner interest:			
Historical units outstanding	79,726	74,667	74,667
As reported	$ 0.69	$ 0.40	$ 0.21
Pro forma	$ 0.69	$ 0.40	$ 0.21

Estimates

Preparing Enterprise GP Holdings L.P. s financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our actual results could differ from these estimates.

Exchange Contracts

Exchanges are contractual agreements for the movements of NGL and petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued and included in accounts receivable, and net exchange volumes loaned to us under such agreements are valued and accrued as a liability in accrued gas payables.

Receivables and payables arising from exchange transactions are satisfied with products rather than cash. When monetary consideration is required for product differentials and service costs such items are recognized on a net basis.

Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with business combination or with a disposal activity covered by SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS 146, *Accounting for Costs Associated with Exit and Disposal Activities*, we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan.

Financial Instruments

We use financial instruments such as swaps, forward and other contracts to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. We recognize our transactions on the balance sheet as assets and liabilities based on the instrument s fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. Changes in fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses from the instrument will be recorded on the income statement to offset corresponding losses and gains of the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses from the instrument are recorded in other comprehensive income. Gains and losses on cash flow hedges are reclassified from other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the underlying asset. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness is immediately recognized in earnings. See Note 7 for a further discussion of our financial instruments.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for recoverability (i) on an annual basis during the second quarter of each year or (ii) on an interim basis when impairment indicators are present. If such indicators are present (e.g., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit to which the goodwill is assigned will be calculated and compared to its book value.

If the fair value of the reporting unit exceeds its book value, the goodwill amount is not considered to be impaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value, a charge to earnings is recorded to adjust the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented. See Note 13 for a further discussion of our goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values in accordance with SFAS 144. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, a non-cash asset impairment charge is recognized equal to the excess of the asset s carrying value over its fair value. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm s-length transaction. We measure fair value using market prices or, in the absence of such data, appropriate valuation techniques.

We recognized non-cash asset impairment charges of $4.1 million and $1.2 million in 2004 and 2003, respectively, which are reflected as components of operating costs and expenses. No asset impairment charges were recorded in 2005.

Impairment Testing for Unconsolidated Affiliates

We evaluate equity method investments (which include excess cost amounts attributable to tangible or intangible assets) for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the investee or long-term negative changes in the investee s industry. In the event that we determine that the loss in value of an investment is other than a temporary decline, we would record a charge to earnings to adjust the carrying value to fair value.

We had no such impairment charges during 2005 or 2004; however, a former unconsolidated affiliate recorded a $67.5 million asset impairment charge during 2003. Our share of this charge was $22.5 million, which was recorded as a reduction in equity earnings from this investee during 2003. See Note 11 for additional information regarding this non-cash charge.

Income taxes

Our limited partnership structure is not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our individual partners. We are organized as a pass-through entity for federal income tax purposes. As a result, our partners are individually responsible for the federal income tax on their allocable share of our taxable income. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholder s tax attributes in us.

Provision for income taxes is primarily applicable to certain federal and state tax obligations related to our Seminole Pipeline and Dixie Pipeline. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. See Note 19 for additional information regarding our provision of income taxes.

Inventories

Our inventories primarily consist of NGL, petrochemical and natural gas volumes and are valued at the lower of average cost or market. We capitalize as a cost of inventory shipping and handling charges directly related to volumes we (i) purchase from third parties or (ii) take title to in connection with processing or other agreements. As these volumes are sold and delivered out of inventory, the average cost of these products (which includes freight-in charges which have been capitalized) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 9 for a further discussion of our inventories.

Costs and expenses, as shown on our Statements of Consolidated Operations and Comprehensive Income, include cost of sales related to inventories. Our consolidated cost of sales amounts were $10.3 billion, $7.2 billion and $4.5 billion during 2005, 2004 and 2003, respectively.

Minority Interest

Minority interest represents third-party and related party ownership interests in the net assets of certain of our subsidiaries. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of the parent company, with any third-party investor s ownership in our consolidated balance sheet amounts shown as minority interest. The following table shows the components of minority interest at the dates indicated:

	December 31, 2005	**December 31, 2004**
Third-party owners of Enterprise Products GP		$ 90,845
Limited partners of Enterprise Products Partners:		
Third-party owners of Enterprise Products Partners	$ 4,403,490	4,305,309
Related party owners of Enterprise Products Partners	420,378	489,349
Joint venture partners	103,169	71,040
Total minority interest on consolidated balance sheet	$ 4,927,037	$ 4,956,543

The minority interest attributable to third-party ownership of Enterprise Products GP consists of El Paso s 9.9% member interest during the fourth quarter of 2004. We granted El Paso a 9.9% member interest in Enterprise Products GP in connection with the GulfTerra Merger. In January 2005, an affiliate of EPCO acquired El Paso s 9.9% membership interest in Enterprise Products GP and 13,454,498 common units of Enterprise Products Partners from El Paso for approximately $425 million in cash. Upon completion of EPCO s purchase of El Paso s 9.9% ownership interest in Enterprise Products GP, EPCO and its affiliates owned 100% of the membership interests in Enterprise Products GP.

The minority interest attributable to the limited partners of Enterprise Products Partners consists of common units held by the public and affiliates of Enterprise GP Holdings L.P. (primarily EPCO), and is net of unamortized deferred compensation of $14.6 million and $10.9 million at December 31, 2005 and December 31, 2004, respectively, which represents the value of restricted common units of Enterprise Products Partners issued to key employees of EPCO.

The minority interest attributable to joint venture partners as of December 31, 2005, is primarily attributable to our partners in Tri-States, Seminole, Wilprise, Independence Hub, Dixie and Belle Rose. As of December 31, 2004, the minority interest attributable to joint venture partners is primarily attributable to our partners in Tri-States, Seminole, Wilprise, Independence Hub and the Mid-America pipeline system.

The following table reflects the components of minority interest expense for the periods indicated:

	December 31, 2005	December 31, 2004	December 31, 2003
Third-party owners of Enterprise Products GP		$ 891	$ 4,296
Limited Partners of Enterprise Products Partners	$ 347,882	220,588	83,817
Joint venture partners	5,760	8,128	2,966
Total	$ 353,642	$ 229,607	$ 91,079

The following table shows distributions paid to and contributions from minority interests attributable to each component of minority interest for the periods indicated:

	December 31, 2005	December 31, 2004	December 31, 2003
Distributions paid to minority interests:			
Third-party owners of Enterprise Products GP		$ 1,572	$ 2,850
Limited partners of Enterprise Products Partners	$ 633,973	398,247	287,387
Joint venture partners	5,725	6,440	4,964
Total	$ 639,698	$ 406,259	$ 295,201
Contributions from minority interests:			
Third-party owners of Enterprise Products GP		$ 177	
Limited partners of Enterprise Products Partners	$ 633,987	828,956	$ 667,945
Joint venture partners	39,110	9,585	
Total	$ 673,097	$ 838,718	$ 667,945

Distributions paid to the limited partners of Enterprise Products Partners primarily represent the quarterly cash distributions paid by Enterprise Products Partners (excluding the limited partner interests owned by the parent company). Contributions from the limited partners of Enterprise Products Partners primarily represent proceeds Enterprise Products Partners received from common unit offerings (other than cash receipts from the parent company).

Natural Gas Imbalances

Natural gas imbalances result when a customer injects more or less gas into a pipeline than they withdraw. In general, we value our imbalance receivables and payables using a twelve-month moving average of natural gas prices. We believe this valuation method is appropriate given that actual settlement dates may vary by customer. Changes in natural gas prices may impact our estimates. Prior to the GulfTerra Merger, natural gas imbalances were not significant.

At December 31, 2005 and 2004, our imbalance receivables were $89.4 million and $56.7 million, respectively, and are reflected as a component of Accounts receivable trade on our Consolidated Balance Sheets. At December 31, 2005 and 2004, our imbalance payables were $80.5 million and $59 million, respectively, and are reflected as a component of Accrued gas payables on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations from the respective period. Depreciation is recorded over the estimated useful lives of the related assets primarily using the straight-line method for financial statement purposes. We use other depreciation methods (generally accelerated) for tax purposes where appropriate. See Note 10 for additional information regarding our property, plant and equipment.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities.

Asset retirement obligations (AROs) are legal obligations associated with the retirement of tangible long-lived assets that result from its acquisition, construction, development and/or normal operation. We record a liability for AROs when incurred and capitalize an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over its useful life. We will either settle our ARO obligations at the recorded amount or incur a gain or loss upon settlement.

Reclassifications

Certain reclassifications have been made to the financial statements of prior years to conform to the current year presentation. These reclassifications had no effect on reported results of operations or financial position for 2004 and 2003.

In 2005, we reclassified changes in restricted cash balances (as shown on our Statements of Cash Flows) from operating activities to investing activities in response to best accounting practices. In order to conform the Statements of Cash Flows for 2004 and 2003 to the current period presentation, we reclassified the $12.3 million and $5.1 million increases in restricted cash balances during 2004 and 2003, respectively, from operating activities to investing activities.

Restricted Cash

Restricted cash represents amounts held by a brokerage firm in connection with (i) our commodity financial instruments portfolio and (ii) physical natural gas purchases made on the NYMEX exchange.

Revenue Recognition

See Note 4 for information regarding our revenue recognition policies.

Start-Up and Organization Costs

Start-up costs and organization costs are expensed as incurred. Start-up costs are defined as one-time activities related to opening a new facility, introducing a new product or service, conducting activities in a new territory, pursuing a new class of customer, initiating a new process in an existing facility, or some new operation. Routine ongoing efforts to improve existing facilities, products or services are not start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

3. Recent Accounting Developments

The following information summarizes recently issued accounting guidance that will (or may) affect our financial statements in the future:

SFAS 123(R), *Share-Based Payment*, eliminates the ability to account for share-based compensation transactions using APB 25 and generally requires instead that such transactions be accounted for using a fair value method. Historically, we have accounted for our share-based transactions using APB 25. We adopted SFAS 123(R) on January 1, 2006, which resulted in a nominal impact to our financial statements. During 2006, we expect to record compensation expense of $7.1 million associated with the fair value method of accounting for profits interests and Enterprise Products Partners unit options and nonvested (or restricted) units using SFAS 123(R) based on awards outstanding at January 1, 2006.

SFAS 154, *Accounting Changes and Error Corrections*, provides guidance on the accounting for and reporting of accounting changes and error corrections. We adopted SFAS 154 on January 1, 2006.

Emerging Issues Task Force (EITF) 04-13, *Accounting for Purchases and Sale of Inventory With the Same Counterparty*, requires that two or more inventory transactions with the same counterparty should be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. We are still evaluating this recent guidance, which is effective April 1, 2006 for our partnership, but we do not believe that our revenues or costs and expenses will be materially affected.

4. Revenue Recognition

We recognize revenue using the following criteria: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer s price is fixed or determinable and (iv) collectibility is reasonably assured. We generally do not take title to products gathered, transported or processed unless noted below. The following information summarizes our revenue recognition policies by business segment:

NGL Pipelines & Services

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds, fee-based contracts, hybrid contracts (mixed percent-of-liquids and fee-based) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer s natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of-proceeds contract, we share in the proceeds generated from the producer s sale of the mixed NGLs we extract on their behalf. Revenue is recognized under percent-of-proceeds arrangements when the extracted NGLs are delivered and sold to customers. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue in the period the services are provided.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC.

Under our NGL and related product storage contracts, we collect a fee based on the number of days a customer has volumes in storage multiplied by a storage rate for each product. Under these contracts, revenue is recognized ratably over the length of the storage period based on the storage fees specified in each contract.

Revenues from product terminalling contracts (applicable to our import and export operations) are recorded in the period services are provided. Customers are typically billed in a fee per unit of volume loaded or unloaded. In our export operations, we may also record revenues related to demand fees we charge customers who reserve to use our export facilities and later fail to do so. We recognize such demand fee revenue when the customer fails to utilize our facilities as required by contract.

In our NGL fractionation business, we enter into fee-based arrangements and percent-of-liquids contracts. Under our fee-based arrangements, we recognize revenue in the period the services are provided. These fee-based arrangements typically include a base-processing fee (typically in cents per gallon) that is subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At certain of our NGL fractionation facilities, we generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the NGLs fractionated for customers as payment for our services. We recognize revenue from such arrangements when the NGLs we retain are sold and delivered to customers.

Onshore Natural Gas Pipelines & Services

Certain of our onshore natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission (FERC). Revenues associated with these fee-based contracts are recognized when volumes have been physically delivered to our customer through the pipeline.

In addition, we have natural gas sales contracts associated with some of our onshore natural gas pipelines whereby revenue is recognized when we sell and deliver a volume of natural gas to a customer. Revenues from these sales contracts are based upon market-related prices as determined by the individual agreements.

Under our natural gas storage contracts, there are typically two components of revenues: (i) fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage of the storage facilities, and (ii) storage fees per unit of volume stored at the facilities. Revenues from demand payments are recognized throughout the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Offshore Pipelines & Services

Our revenues from offshore natural gas pipelines are derived from fee-based contracts and are typically based on transportation fees per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. We recognize revenue when volumes have been physically delivered for the customer through the pipeline.

The majority of our revenues from offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along our crude oil pipelines for an index-based price (less a price differential) and sell the oil back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on the price differential per unit of volume (typically in barrels) multiplied by the volume delivered. We recognize revenues from such arrangements when we complete the delivery of crude oil to the purchaser.

In addition, certain of our offshore crude oil pipelines generate revenues based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. We recognize revenues from these gathering contracts when we complete delivery of the crude oil for the producer.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees represent fixed-fees charged to customers who use our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractual fixed period of time. Revenues for platform services, including both demand fees and commodity charges, are recognized in the period the services are provided.

Petrochemical Services

We enter into isomerization and propylene fractionation fee-based processing arrangements and petrochemical product sales contracts. Under our processing arrangements, we recognize revenue in the period the services are provided. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations.

Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. Revenues from these sales contracts are recognized when the products are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

5. Accounting for Equity Awards

As discussed in Note 2, we will account for our equity awards using the provisions of SFAS 123(R) beginning January 1, 2006. See Notes 2 and 3 for information regarding our adoption of this new accounting guidance. The following discussion pertains to our historical practice of accounting for equity awards using the intrinsic value method described in APB 25.

Unit Options

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the 1998 Plan). Under this program, non-qualified incentive options to purchase a fixed number of Enterprise Products Partners common units may be granted to EPCO s key employees who perform management, administrative or operational functions for us. The exercise price per unit, vesting and expiration terms, and rights to receive distributions on units granted are determined by EPCO for each grant agreement. EPCO has not granted the right to receive distributions on unvested unit options of Enterprise Products Partners. EPCO purchases common units of Enterprise Products Partners to fund its obligations under the 1998 Plan at fair value either in the open market or from Enterprise Products Partners.

Historically, we accounted for Enterprise Products Partners' unit options using the intrinsic value method described in APB 25. The exercise price of each option granted was equivalent to or greater than the market price of the underlying equity at the date of grant. Accordingly, no compensation expense related to Enterprise Products Partners' unit options has been recognized in our Statements of Consolidated Operations and Comprehensive Income for the periods presented.

When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee. Our option-related reimbursements were $9.2 million, $3.8 million and $2.7 million in 2005, 2004 and 2003, respectively.

Summary of 1998 Plan activity

The information in the following table shows unit option activity for the Enterprise Products Partners common unit options issued by EPCO to personnel who work on our behalf.

	Number of Units	Weighted-average strike price
Outstanding at December 31, 2002	2,310,078	$ 14.57
Granted	35,000	22.26
Exercised	(372,078)	7.10
Forfeited	(35,000)	18.86
Outstanding at December 31, 2003	1,938,000	16.07
Granted	910,000	22.17
Exercised	(385,000)	12.79
Outstanding at December 31, 2004	2,463,000	18.84
Granted	530,000	26.49
Exercised	(826,000)	14.77
Forfeited	(85,000)	24.73
Outstanding at December 31, 2005	2,082,000	22.16
Options exercisable at:		
December 31, 2003	509,000	$ 9.68
December 31, 2004	1,154,000	$ 14.65
December 31, 2005	727,000	$ 19.19

The following table provides additional information regarding the unit options outstanding at December 31, 2005 to purchase Enterprise Products Partners common units:

				Options Exercisable at December 31, 2005	
Range of Strike Prices	**Options outstanding at December 31, 2005**	**Weighted Average Remaining Contractual Life (in Years)**	**Weighted Average Strike Price**	**Number Exercisable at December 31, 2005**	**Weighted Average Strike Price**
$9.00 - $12.56	118,000	4.41	$ 10.68	118,000	$ 10.68
$15.93 - $17.63	225,000	5.14	16.47	225,000	16.47
$20.00 - $24.73	1,249,000	7.84	22.57	384,000	23.40
$26.47 - $26.95	490,000	9.57	26.49		n/a
	2,082,000			727,000	

The weighted-average fair value of options granted during 2005, 2004 and 2003 was $1.35, $2.26 and $2.17 per option, respectively.

Employee Partnership

In connection with the initial public offering of the parent company in August 2005, EPE Unit L.P. (the Employee Partnership) was formed to serve as an incentive arrangement for certain employees of EPCO through a profits interest in the Employee Partnership. For additional information regarding the Employee Partnership, see *Relationship with EPCO and affiliates* under Note 18.

EPCO accounted for this share-based compensation arrangement under APB 25 until it adopted SFAS 123(R) on January 1, 2006. Under APB 25, the intrinsic value of the Class B limited partnership interest was accounted for similar to a stock appreciation right. EPCO's compensation expense related to this share-based compensation arrangement is allocated to us and other affiliates of EPCO pursuant to an administrative services agreement. For the year ended December 31, 2005, we were allocated $2.1 million of non-cash compensation expense associated with this share-based compensation arrangement.

Nonvested Units

Enterprise Products Partners began issuing nonvested (or restricted) common units to key employees of EPCO and directors of Enterprise Products GP in 2004. In general, Enterprise Products Partners' restricted common units are classified as either time-vested or performance-based. Time-vested restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on time-vested restricted common units lapse four years from the date of grant.

Unearned compensation, representing the fair market value of such restricted units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the vesting period. During the vesting period, each holder of time-vested restricted units is entitled to receive cash distributions per unit in an amount equal to those received by Enterprise Products Partners' common unitholders.

In general, Enterprise Products Partners' performance-based restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) if Enterprise Products Partners achieves a specified level of financial performance for certain capital projects during 2007. If the specified financial targets are not met by the dates identified within each agreement, these units will be forfeited. However, at December 31, 2005, we believe it is probable that financial performance will be met. Unearned compensation, representing the fair market value of these units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the performance period. The performance-based restricted units are not entitled to vote or to receive distributions from Enterprise Products Partners, until after (and if) the specified level of target performance is achieved.

At December 31, 2005, Enterprise Products Partners had 751,604 restricted common units outstanding, which includes 724,454 time-vested restricted units and 27,150 performance-based restricted units. Unearned compensation attributable to restricted units was $14.6 million and $10.9 million at December 31, 2005 and 2004, respectively. Compensation expense of $3.4 million and $0.8 million was amortized to earnings in 2005 and 2004, respectively.

Parent Company s Long-Term Incentive Plan

In November 2005, the parent company filed a registration statement covering the potential future issuance of 250,000 of its units in connection with a long-term incentive plan of EPCO (the 2005 Plan). The 2005 Plan was established to encourage directors of EPE Holdings and employees of EPCO that perform services for the parent company to increase their ownership of parent company units and to develop a sense of proprietorship and personal involvement in the parent company s and Enterprise Product Partners business and financial success. The 2005 Plan provides for the future issuance of unit options, restricted units or phantom units of the parent company (limited to 250,000 units). No awards have been issued under the 2005 Plan as of December 31, 2005.

6. Employee Benefit Plans

During the first quarter of 2005, we acquired a controlling ownership interest in Dixie Pipeline Company (Dixie), which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined contribution plan. Dixie contributed $0.3 million to its company-sponsored defined contribution plan during 2005.

Pension and postretirement benefit plans. Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's postretirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table shows Dixie's benefit obligations, fair value of plan assets, unfunded liabilities and accrued benefit liabilities at December 31, 2005.

	Pension Plan	**Postretirement Plan**
Projected benefit obligation	$ 9,434	$ 4,505
Accumulated benefit obligation	7,023	4,505
Fair value of plan assets	4,954	
Unfunded liability	4,480	4,505
Accrued benefit liability	4,348	4,747

Dixie's net pension and postretirement benefit costs for 2005 were $0.6 million and $0.2 million, respectively. Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining net periodic benefit costs for 2005 were as follows: discount rate of 5.75%; expected long-term return on plan assets of 7%; rate of compensation increase of 4%; and a medical trend rate of 7% in 2005 grading to an ultimate trend of rate of 5% in 2007 and later years. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2005 were as follows: discount rate of 5.5%, expected long-term rate of return on assets of 7%; rate of compensation increase of 4%; and a medical trend rate of 6% for 2006 grading to an ultimate trend of 5% for 2007 and later years.

Future benefits expected to be paid from Dixie's pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	**Postretirement Plan**
2006	$ 448	$ 272
2007	682	289
2008	558	283
2009	800	302
2010	832	330
2011 through 2015	4,804	1,883
Total	$ 8,124	$ 3,359

7. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings, fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument s gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133. We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise Products GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business environment.

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2005 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	**Number Of Swaps**	**Period Covered by Swap**	**Termination Date of Swap**	**Fixed to Variable Rate** (1)	**Notional Amount**
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 7.26%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.8%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 5.24%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 4.99%	$200 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These eleven agreements have a combined notional amount of $1.1 billion and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month London interbank offered rate (LIBOR) (plus an applicable margin as defined in each swap agreement), and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the settlement period). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

The total fair value of these eleven interest rate swaps at December 31, 2005, was a liability of $19.2 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2005 and 2004 reflects a $10.8 million and $9.1 million benefit from these swap agreements, respectively.

During the first nine months of 2004, we entered into eight forward starting interest rate swaps having an aggregate notional value of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these financial instruments was to effectively hedge the underlying U.S. treasury rate related to our issuance of $2 billion in principal amount of fixed-rate debt. In October 2004, the Operating Partnership issued $2 billion of private placement debt under Senior Notes E through H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS 133.

In April 2004, we elected to terminate the initial four forward starting swaps in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. In September 2004, we settled the remaining four swaps resulting in an $85.1 million payment to the counterparties.

The following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each swap upon settlement:

Term of Anticipated Debt Offering (or Forecasted Transaction)	**Notional Amount of Debt covered by Forward Starting Swaps**	**Net Cash Received upon Settlement of Forward Starting Swaps**
3-year, fixed rate debt instrument	$ 500,000	$ 4,613
5-year, fixed rate debt instrument	500,000	7,213
10-year, fixed rate debt instrument	650,000	10,677
30-year, fixed rate debt instrument	350,000	(3,098)
Total	$ 2,000,000	$ 19,405

The net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income (AOCI) to reduce interest expense over the life of the associated debt. We reclassified $4 million and $1.3 million from AOCI during 2005 and 2004, respectively, which reduced the amount of interest expense we recognized.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with natural gas and NGLs, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas or NGLs. The commodity financial instruments we utilize may be settled in cash or with another financial instrument. Historically, we have not hedged our exposure to risks associated with petrochemical products, including MTBE.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise Products GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise Products GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

At December 31, 2005, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of economic hedges. The fair value of our commodity financial instrument portfolio at December 31, 2005 was a liability of $0.1 million. We recorded nominal amounts of earnings from our commodity financial instruments during 2005, 2004 and 2003.

Fair value information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques.

The following table presents the estimated fair values of our financial instruments at the dates indicated:

	December 31, 2005		**December 31, 2004**	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 57,602	$ 57,602	$ 51,163	$ 51,163
Accounts receivable	1,451,103	1,451,103	1,083,526	1,083,526
Commodity financial instruments [1]	1,114	1,114	3,904	3,904
Interest rate hedging financial instruments [2]			505	505
Financial liabilities:				
Accounts payable and accrued expenses	1,765,498	1,765,498	1,468,933	1,468,933
Fixed-rate debt (principal amount)	4,359,067	4,395,110	4,091,902	4,288,892
Variable-rate debt	641,500	641,500	563,229	563,229
Commodity financial instruments [1]	1,167	1,167	3,685	3,685
Interest rate hedging financial instruments [2]	19,179	19,179		

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

(2) Represent interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

8. Cumulative Effect of Changes in Accounting Principles

Our Statements of Consolidated Operations and Comprehensive Income reflect the following cumulative effects of changes in accounting principles:

Our adoption of FIN 47 in December 2005 resulted in a charge of $4.2 million, of which $0.2 million is presented as the cumulative effect of a change in accounting principle for the parent company. The remaining $4 million is a component of minority interest expense since the limited partners of Enterprise Products Partners (other than the parent company) were allocated their share of this charge.

In 2004, we changed the method a subsidiary used to account for its planned major maintenance activities and the method we used to account for our investment in Venice Energy Services Company, LLC (VESCO). These changes resulted in a combined $10.8 million benefit, of which $0.2 million is presented as the cumulative effect of a change in accounting principle for the parent company. The remaining $10.6 million benefit is a component of minority interest expense.

Implementation of FIN 47. In December 2005, we adopted Financial Accounting Standards Board (FIN) 47, which required us to record a liability for asset retirement obligations (AROs) in which the timing and/or amount of settlement of the obligation are uncertain. These conditional asset retirement obligations were not addressed in SFAS 143, which we adopted on January 1, 2003. We recorded a cumulative effect of change in accounting principle of $4.2 million in connection with our implementation of FIN 47, which represents the depreciation and accretion expense we would have recognized had we recorded these conditional asset retirement obligations when incurred. For additional information regarding our asset retirement obligations, see Note 10.

BEF major maintenance costs. In January 2004, our Belvieu Environmental Fuels (BEF) subsidiary changed its accounting method for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred approach. BEF owns an octane additive production facility that undergoes periodic planned outages of 30 to 45 days for major maintenance work. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services, and other related items. This change conformed BEF s accounting policy for such costs to that followed by our other operations, which use the expense-as-incurred approach. As such, we believe the change is to a method that is preferable under the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

Investment in VESCO. In July 2004, we changed the method we use to account for our investment in VESCO from the cost method to the equity method in accordance with EITF 03-16, *Accounting for Investments in Limited Liability Companies.* EITF 03-16 requires partnership-type accounting for investments in limited liability companies that have separate ownership accounts for each investor. As a result of EITF 03-16, investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3% to 5%) than the traditional 20% threshold applied under APB 18, *The Equity Method of Accounting for Investments in Common Stock.*

Prior to adopting EITF 03-16, we accounted for our 13.1% investment in VESCO using the cost method. As a result, we recognized dividend income from VESCO to the extent we received cash distributions from them. Our cumulative effect adjustment for EITF 03-16 represents (i) equity earnings from VESCO that would have been recorded had we used the equity method of accounting prior to 2004 less (ii) the dividend income we recorded from VESCO prior to 2004 using the cost method. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

113

For the periods indicated, the following table shows unaudited pro forma net income for the years ended December 31, 2005, 2004 and 2003, assuming the three accounting changes noted above were applied retroactively to January 1, 2003.

	For the Year Ended December 31, 2005	2004	2003
Pro Forma income statement amounts:			
Historical net income	$ 55,276	$ 29,778	$ 15,861
Adjustments to derive pro forma net income:			
Effect of implementation of FIN 47			
Remove cumulative effect of change in accounting principle recorded in December 2005	227		
Record depreciation and accretion expense associated with conditional asset retirement obligations	(735)	(373)	(246)
Effect of change from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:			
Remove historical equity losses recorded for BEF			31,508
Record equity income from BEF calculated using new method of accounting for major maintenance costs			(31,800)
Remove cumulative effect of change in accounting principle recorded in January 2004		(140)	
Effect of changing from the cost method to the equity method with respect to our investment in VESCO:			
Remove cumulative effect of change in accounting principle recorded in July 2004		(76)	
Remove historical dividend income recorded from VESCO		(2,136)	(5,595)
Record equity earnings from VESCO		2,429	5,133
Effect of changes on minority interest of Enterprise GP Holdings L.P.	720	78	980
Pro forma net income	55,488	29,560	15,841
General partner interest	(6)	(3)	(2)
Pro forma net income available to limited partners	$ 55,482	$ 29,557	$ 15,839
Pro forma per unit data (basic):			
Historical units outstanding	79,726	74,667	74,667
Per unit data:			
As reported	$ 0.69	$ 0.40	$ 0.21
Pro forma	$ 0.70	$ 0.40	$ 0.21
Pro forma per unit data (diluted):			
Historical units outstanding	79,726	74,667	74,667
Per unit data:			
As reported	$ 0.69	$ 0.40	$ 0.21
Pro forma	$ 0.70	$ 0.40	$ 0.21

9. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31, 2005	2004
Working inventory	$ 279,237	$ 171,485
Forward-sales inventory	60,369	17,534
Inventory	$ 339,606	$ 189,019

A general description of our inventories is as follows:

Our regular trade (or working) inventory is primarily comprised of inventories of natural gas, NGLs and petrochemical products that are available for sale or used in the provision of services. This inventory is valued at the lower of average cost or market, with market being determined by industry-related posted prices such as those published by Oil Price Information Service (OPIS) and Chemical Market Associates, Inc. (CMAI).

The forward-sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts and is valued at the lower of average cost or market, with market being defined as the weighted-average sales price for NGL volumes to be delivered in future months on the forward sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes and other related costs including terminal and storage fees, vessel inspection and demurrage charges and processing costs.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-related prices during the month in which they are acquired. As with inventory volumes we purchase for cash, we capitalize as a component of inventory those ancillary costs (e.g. freight-in and other handling and processing charges) incurred in connection with volumes obtained through such contracts.

Due to fluctuating market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market (LCM) adjustments when the cost of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses and generally affect our segment operating results in the following manner:

NGL inventory write-downs are recorded as a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;

Natural gas inventory write downs are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and

Petrochemical inventory write downs are recorded as a cost of our petrochemical marketing activities or octane additive production business within our Petrochemical Services business segment, as applicable.

For the years ended December 31, 2005, 2004 and 2003, we recognized LCM adjustments of approximately $21.9 million, $9.4 million and $16.9 million, respectively. The majority of these write-downs were taken against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 7 for a description of our commodity hedging activities.

10. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	At December 31, 2005	2004
Plants and pipelines (1)	5-35 (5)	$ 8,209,580	$ 7,691,197
Underground and other storage facilities (2)	5-35 (6)	549,923	531,394
Platforms and facilities (3)	23-31	161,807	162,645
Transportation equipment (4)	3-10	24,939	7,240
Land		38,757	29,142
Construction in progress		854,595	230,375
Total		9,839,601	8,651,993
Less accumulated depreciation		1,150,577	820,526
Property, plant and equipment, net		$ 8,689,024	$ 7,831,467

(1) Plants and pipelines includes processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.

(2) Underground and other storage facilities includes underground product storage caverns; storage tanks; water wells; and related assets.

(3) Platforms and facilities includes offshore platforms and related facilities and other associated assets.

(4) Transportation equipment includes vehicles and similar assets used in our operations.

(5) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings 20-35 years; and laboratory and shop equipment, 5-35 years.

(6) In general, the estimated useful lives of major components of this category are: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

Depreciation expense for the years ended December 31, 2005, 2004 and 2003 was $328.7 million, $161 million and $101 million, respectively. A significant portion of the year-to-year increase in depreciation expense between 2005 and 2004 is attributable to assets we acquired in connection with the GulfTerra Merger, which was completed on September 30, 2004.

We capitalized $22 million, $2.8 million and $1.6 million of interest associated with construction projects during 2005, 2004 and 2003, respectively.

Asset retirement obligations. We have recorded asset retirement obligations related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our asset retirement obligations primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our asset retirement obligations may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

Previously, we recorded asset retirement obligations associated with the future retirement and removal activities of certain offshore assets located in the Gulf of Mexico. In December 2005, we adopted FIN 47 and recorded an additional $10.1 million in connection with conditional asset retirement obligations. The cumulative effect of this change in accounting principle for years prior to 2005 was a non-cash charge of $4.2 million at the Enterprise Products Partners level. None of our assets are legally restricted for purposes of settling asset retirement obligations.

The following table presents information regarding our asset retirement obligations since December 31, 2004.

Asset retirement obligation liability balance, December 31, 2004	$ 6,236
Adoption of FIN 47 for conditional obligations	10,076
Accretion expense	483
Asset retirement obligation liability balance, December 31, 2005	$ 16,795

Property, plant and equipment at December 31, 2005 and 2004 includes $0.9 million and $0.2 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Also, based on information currently available, we estimate that accretion expense will approximate $1.4 million for 2006, $1.1 million for 2007, $1.2 million for 2008, $1.3 million for 2009 and $1.4 million for 2010.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2005 and 2004 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

11. Investments in and Advances to Unconsolidated Affiliates

Our investments in and advances to our unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 17. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at December 31, 2005	Investments in and advances to Unconsolidated Affiliates at December 31, 2005	December 31, 2004
NGL Pipelines & Services:			
Dixie Pipeline Company (Dixie)[1]			$ 32,514
Venice Energy Services Company, LLC (VESCO)	13.1%	$ 39,689	38,437
Belle Rose NGL Pipeline LLC (Belle Rose)[2]			10,172
K/D/S Promix LLC (Promix)	50%	65,103	65,748
Baton Rouge Fractionators LLC (BRF)	32.3%	25,584	27,012
Onshore Natural Gas Pipelines & Services:			
Evangeline [3]	49.5%	3,151	2,810
Coyote Gas Treating, LLC (Coyote)	50%	1,493	2,441
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (Poseidon)	36%	62,918	63,944
Cameron Highway Oil Pipeline Company (Cameron Highway)[4]	50%	58,207	114,354
Deepwater Gateway, L.L.C. (Deepwater Gateway)[5]	50%	115,477	56,527
Neptune Pipeline Company, L.L.C. (Neptune)	25.67%	68,085	72,052
Nemo Gathering Company, LLC (Nemo)	33.92%	12,157	12,586
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (BRPC)	30%	15,212	15,617
La Porte [6]	50%	4,845	4,950
Total		$ 471,921	$ 519,164

(1) We acquired an additional 20% ownership interest in Dixie in January 2005 and an additional 26.1% ownership interest in February 2005. As a result of these acquisitions, Dixie became a consolidated subsidiary.

(2) We acquired an additional 41.7% ownership interest in Belle Rose in June 2005. As a result of this acquisition, Belle Rose became a consolidated subsidiary.

(3) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

(4) Cameron Highway began deliveries of Gulf of Mexico crude oil production to major refining markets along the Texas Gulf Coast during the first quarter of 2005. In June 2005, we received a $47.5 million return of our investment in Cameron Highway due to the refinancing of Cameron Highway s project debt. For additional information regarding the refinancing of Cameron Highway's debt, please read Note 14.

(5) In March 2005, we contributed $72 million to Deepwater Gateway to fund our share of the repayment of its $144 million term loan. For additional information regarding Deepwater Gateway's repayment of its term loan, please read Note 14.

(6) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire an ownership interest in an investee exceeds the carrying value of the historical net assets of the investee we are purchasing. Such excess amounts (or excess costs) are a component of our investments in and advances to unconsolidated affiliates.

At December 31, 2005, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost amounts. At the time of purchase, an analysis of each of these investments indicated that such excess cost amounts were attributable to either (i) an increase in the fair value of tangible or qualifying intangible assets owned by each entity over its historical carrying values for such assets or (ii) it was unattributable and deemed to be goodwill.

To the extent that we attribute all or a portion of an excess cost amount to an increase in the fair value of assets, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment.

At December 31, 2005, our investments in and advances to unconsolidated affiliates included $48.1 million of excess cost amounts, all of which were attributed to increases in fair value of the underlying assets of the investees. At December 31, 2004, our excess cost amounts totaled $83.6 million, of which $74.3 million was attributed to increases in fair value of the underlying assets and the remainder to goodwill. The decrease in total excess cost during 2005 is due to the consolidation of Dixie and amortization of excess cost amounts attributable to the fair value of underlying assets. Equity earnings from unconsolidated affiliates were reduced by $2.3 million, $1.9 million and $1.6 million during 2005, 2004 and 2003, respectively, due to the amortization of excess cost amounts.

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31, 2005	2004	2003
NGL Pipelines & Services:			
Dixie [(1)]	$ 1,103	$ 1,273	$ 1,323
VESCO [(2)]	1,412	6,132	
Belle Rose [(1)]	(151)	(402)	(55)
Promix	1,876	859	2,106
BRF	1,313	2,190	832
Tri-States NGL Pipeline LLC (Tri-States [(1)])		(154)	1,542
Wilprise Pipeline Company, LLC (Wilprise [(1)])			276
EPIK [(1,3)]			1,818
Onshore Natural Gas Pipelines & Services:			
Evangeline	331	231	131
Coyote	2,053	541	
Offshore Pipelines & Services:			
Poseidon	7,279	2,509	
Cameron Highway [(4)]	(15,872)	(461)	
Deepwater Gateway	10,612	3,562	
Neptune	2,019	(1,852)	1,014
Nemo	1,774	1,628	1,268
Starfish Pipeline Company, LLC (Starfish [(5)])	313	3,473	3,279
Petrochemical Services:			
BRPC	1,224	1,943	1,198
La Porte	(738)	(710)	(698)
Belvieu Environmental Fuels, L.P. (BEF [(1)])			(27,864)
Olefins Terminal Corporation (OTC [(1)])			(77)
Other:			
Gulf Terra GP [(6)]		32,025	(53)
Total	$ 14,548	$ 52,787	$ (13,960)

(1) We acquired additional ownership interests in or control over these entities since January 1, 2003 resulting in our consolidation of each company s post-acquisition financial results with those of our own. Our consolidation of each company s post-acquisition financial results began in the following periods: EPIK, March 2003; Wilprise, October 2003; OTC, August 2003; BEF, September 2003; Tri-States, April 2004; Dixie, February 2005; and Belle Rose, June 2005.

(2) As a result of adopting EITF 03-16 during 2004, we changed from the cost method to the equity method of accounting with respect to our investment in VESCO. See Note 8 for information regarding this accounting change.

(3) EPIK refers to EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively.

(4) Equity earnings from Cameron Highway for the year ended December 31, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway's project debt (see Note 14).

(5) We were required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish. On March 31, 2005, we sold this asset to a third-party.

(6) In connection with the GulfTerra Merger (see Note 12), GulfTerra GP became a wholly owned consolidated subsidiary of ours on September 30, 2004. We had previously accounted for our 50% ownership interest in GulfTerra GP as an equity method investment from December 15, 2003 through September 29, 2004.

NGL Pipelines & Services

At December 31, 2005, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

VESCO. We own a 13.1% interest in VESCO, which owns a natural gas processing and NGL fractionation facility and related storage and pipeline assets located in south Louisiana. On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16 (see Note 8).

Promix. We own a 50% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

BRF. We own an approximate 32.3% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2005	**2004**
BALANCE SHEET DATA:		
Current assets	$ 72,784	$ 93,017
Property, plant and equipment, net	328,270	348,168
Other assets	12,471	13,017
Total assets	$ 413,525	$ 454,202
Current liabilities	$ 32,886	$ 72,427
Other liabilities	7,343	6,882
Combined equity	373,296	374,893
Total liabilities and combined equity	$ 413,525	$ 454,202

	For Year Ended December 31,		
	2005	**2004**	**2003**
INCOME STATEMENT DATA:			
Revenues	$ 207,775	$ 244,521	$ 258,939
Operating income	6,696	40,259	34,630
Net income	6,509	40,355	34,500

Onshore Natural Gas Pipelines & Services

At December 31, 2005, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Evangeline. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline system located in south Louisiana.

Coyote. We own a 50% interest in Coyote, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,		
	2005	**2004**	
BALANCE SHEET DATA:			
Current assets	$ 41,674	$ 21,652	
Property, plant and equipment, net	36,380	38,821	
Other assets	28,732	35,149	
Total assets	$ 106,786	$ 95,622	
Current liabilities	$ 72,441	$ 24,365	
Other liabilities	32,737	37,210	
Combined equity	1,608	34,047	
Total liabilities and combined equity	$ 106,786	$ 95,622	
	For Year Ended December 31,		
	2005	**2004**	**2003**
INCOME STATEMENT DATA:			
Revenues	$ 347,561	$ 257,539	$ 230,429
Operating income	12,908	8,552	9,275
Net income	4,721	4,657	5,037

Offshore Pipelines & Services

At December 31, 2005, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36% interest in Poseidon, which owns a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana.

Cameron Highway. We own a 50% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. The Cameron Highway Oil Pipeline commenced operations during the first quarter of 2005.

Deepwater Gateway. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo platform located in Green Canyon Block 608 of the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

Neptune. We own a 25.7% interest in Neptune, which owns the Manta Ray Offshore Gathering System and Nautilus System, which are natural gas pipelines located in the Gulf of Mexico.

Nemo. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

In connection with obtaining regulatory approval for the GulfTerra Merger, we were required by the U.S. Federal Trade Commission (FTC) to sell our ownership interest in Starfish by March 31, 2005. We classified the $36.6 million carrying value of this investment under Assets held for sale on our consolidated balance sheet at December 31, 2004. In March 2005, we sold this asset to a third-party for $42.1 million in cash and realized a gain on the sale of $5.5 million.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2005	**2004**
BALANCE SHEET DATA:		
Current assets	$ 141,756	$ 79,196
Property, plant and equipment, net	1,201,926	712,182
Other assets	7,961	528,443
Total assets	$ 1,351,643	$ 1,319,821
Current liabilities	$ 120,611	$ 71,758
Other liabilities	511,633	526,990
Combined equity	719,399	721,073
Total liabilities and combined equity	$ 1,351,643	$ 1,319,821

	For Year Ended December 31,		
	2005	**2004**	**2003**
INCOME STATEMENT DATA:			
Revenues	$ 1,309,836	$ 88,603	$ 76,168
Operating income	78,027	46,938	39,658
Net income	29,161	38,473	33,700

Petrochemical Services

At December 31, 2005, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2005	**2004**
BALANCE SHEET DATA:		
Current assets	$ 5,508	$ 3,266
Property, plant and equipment, net	54,751	57,516
Total assets	$ 60,259	$ 60,782
Current liabilities	$ 1,178	$ 438
Other liabilities	1	
Combined equity	59,080	60,344
Total liabilities and combined equity	$ 60,259	$ 60,782

	For Year Ended December 31,		
	2005	**2004**	**2003**
INCOME STATEMENT DATA:			
Revenues	$ 16,849	$ 18,378	$ 14,512
Operating income	2,606	5,131	2,726
Net income	2,650	5,151	2,685

Equity earnings from unconsolidated affiliates for 2003 includes a $22.5 million loss related to non-cash impairment charges recorded by BEF, a former unconsolidated affiliate that we now wholly own and consolidate. As a result of declining domestic demand and a prolonged period of weak MTBE production economics, several of BEF s competitors announced their withdrawal from the marketplace during 2003. Due to the deteriorating business environment and outlook for domestic MTBE sales and the completion of its preliminary engineering studies regarding conversion alternatives, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in BEF recognizing a non-cash asset impairment charge of $67.5 million. Based on our ownership interest at the time, we recorded our 33.3% share of this loss ($22.5 million) in equity earnings from BEF.

Other, non-segment

The Other, non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003, in connection with the GulfTerra Merger. Our $425 million investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

12. Business Combinations and Other Acquisitions

2003 Transactions

Our expenditures for business combinations and acquisitions during 2003 were $37.3 million, which included $4.9 million of purchase price adjustments relating to transactions that occurred prior to 2003.

In March 2003, we purchased an additional 50% ownership interest in EPIK, which owns our NGL export terminal located on the Houston Ship Channel. Also in March 2003, we acquired entities that own the Port Neches petrochemical pipeline. In September 2003, we acquired an additional ownership interest in BEF, which owns our octane additive production facility. In October 2003, we purchased an additional 37.4% ownership interest in Wilprise, which owns an NGL pipeline in Louisiana. In November 2003, we purchased an additional 50% ownership interest in OTC. As a result of these transactions, all of these entities became consolidated subsidiaries of ours.

Our purchase of a 50% equity interest in GulfTerra GP in December 2003 from El Paso was accounted for as an investment in an unconsolidated affiliate (see Note 11). Upon completion of the GulfTerra Merger, GulfTerra GP became a consolidated subsidiary of ours.

2004 Transactions

Our expenditures for business combinations and acquisitions during 2004 were $3.6 billion, which includes consideration paid or granted to complete the GulfTerra Merger in September 2004.

GulfTerra Merger. In September 2004, Enterprise Products Partners completed the merger of GulfTerra with a wholly owned subsidiary of theirs. In addition, Enterprise Products Partners completed certain other transactions related to the merger, including (i) the receipt of Enterprise Products GP s contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise Products GP from El Paso, and (ii) the purchase of certain midstream energy assets located in South Texas from El Paso. As a result of the merger transactions, GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise Products Partners.

The aggregate value of the total consideration Enterprise Products Partners paid or issued to complete the GulfTerra Merger was approximately $4 billion. The merger occurred in several interrelated transactions as described below.

> *Step One*. In December 2003, Enterprise Products Partners purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owned a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise Products Partners investment in GulfTerra GP was accounted for using the equity method of accounting. The $425 million in funds required to complete Step One was borrowed under an interim term loan and the Operating Partnership s pre-merger revolving credit facilities. This borrowing was fully repaid using net proceeds from equity offerings completed by Enterprise Products Partners during 2004.

Step Two. On September 30, 2004, the GulfTerra Merger was completed and GulfTerra and GulfTerra GP became wholly-owned subsidiaries of Enterprise Products Partners. The GulfTerra Merger was accounted for using purchase accounting. Step Two of the GulfTerra Merger included the following transactions:

Immediately prior to closing the GulfTerra Merger, Enterprise Products GP acquired from El Paso the remaining 50% membership interest in GulfTerra GP for $370 million in cash and the issuance of a 9.9% membership interest in Enterprise Products GP to El Paso. Subsequently, Enterprise Products GP contributed this 50% membership interest in GulfTerra GP to Enterprise Products Partners without the receipt of additional general partner interest, common units or other consideration. Enterprise Products GP borrowed the $370 million from an affiliate of EPCO, which obtained the required funds through a loan from EPCO (which at the time indirectly owned the remaining membership interests in Enterprise Products GP).

Immediately prior to closing the GulfTerra Merger, Enterprise Products Partners paid $500 million in cash to El Paso for 10,937,500 Series C units of GulfTerra and 2,876,620 common units of GulfTerra. The remaining 57,762,369 GulfTerra common units were converted into 104,549,823 common units of Enterprise Products Partners, of which 13,454,498 were issued to El Paso.

Step Three. Immediately after Step Two was completed, Enterprise Products Partners acquired certain midstream assets located in South Texas from El Paso for $155.3 million in cash.

In connection with closing the merger transactions, the Operating Partnership borrowed an aggregate $2.8 billion under its credit facilities to fund the cash payment obligations under Steps Two and Three of the GulfTerra Merger and to finance tender offers for GulfTerra s outstanding senior and senior subordinated notes.

The total consideration paid or granted for the GulfTerra Merger (including $7 million of purchase price adjustments paid during 2005) is summarized below:

Step One transaction:	
Cash payment by Enterprise Products Partners to El Paso for initial 50% membership interest in GulfTerra GP (a non-voting interest) made in December 2003	$ 425,000
Total Step One consideration	425,000
Step Two transactions:	
Cash payment by Enterprise Products Partners to El Paso for 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units	500,000
Fair value of equity interests in Enterprise Products Partners granted to acquire remaining 50% membership interest in GulfTerra GP (voting interest) and cash payment of $370 million by Enterprise Products GP to El Paso[(1)]	461,347
Fair value of Enterprise Products Partners common units issued in exchange for remaining GulfTerra common units	2,445,420
Fair value of additional equity interests in Enterprise Products Partners granted for unit awards and Series F2 convertible units in connection with GulfTerra Merger	3,675
Fair value of receivable from El Paso for transition support payments [(2)]	(40,313)
Transaction fees and other direct costs incurred by by Enterprise Products Partners as a result of the GulfTerra Merger [(3)]	31,011
Total Step Two consideration	3,401,140
Total Step One and Step Two consideration	3,826,140
Step Three transaction:	
Purchase of South Texas midstream assets (STMA) from El Paso	155,277
Total consideration for Steps One through Three	$ 3,981,417

(1) This fair value is based on 50% of an implied $922.7 million estimated total fair value of GulfTerra GP, which assumes that the $370 million cash payment made to El Paso by Enterprise Products GP represents consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in Enterprise Products GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise Products GP received. The fair value of $461.3 million assigned to this voting membership interest compares favorably to the $425 million that Enterprise Products Partners paid El Paso to purchase a similar 50% non-voting membership interest in GulfTerra GP in December 2003 (Step One). Subsequently, Enterprise Products GP contributed this 50% membership interest in GulfTerra GP to Enterprise Products Partners without the receipt of additional general partner interest, common units or other consideration.

(2) Reflects the present value of a contract-based receivable from El Paso received as part of the negotiated net consideration reached in Step One of the GulfTerra Merger. The agreements between Enterprise Products Partners and El Paso provide that for a period of three years following the closing of the GulfTerra Merger, El Paso will make transition support payments to Enterprise Products Partners in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. The $45 million receivable from El Paso has been discounted to fair value and recorded as a reduction in the purchase consideration for GulfTerra. As December 31, 2005, the fair value of the current portion and non-current portion of this contract-based receivable was $11.3 million and $8.3 million, respectively; these amounts are reflected as a component of Prepaid and other current assets and Long-term receivables on our Consolidated Balance Sheet as of December 31, 2005.

(3) As a result of the GulfTerra Merger, Enterprise Products Partners incurred expenses of approximately $31 million for various transaction fees and other direct costs. These direct costs include fees for legal, accounting, printing, financial advisory and other services rendered by third-parties to Enterprise Products Partners over the course of the GulfTerra Merger transactions. This amount also includes $3.4 million of involuntary severance costs.

In connection with the GulfTerra Merger, Enterprise Products Partners was required under a consent decree to sell its 50% interest in Starfish, which owns the Stingray natural gas pipeline, and an undivided 50% interest in a Mississippi propane storage facility. Enterprise Products Partners completed the sale of the storage facility in December 2004 and the sale of its investment in Starfish in March 2005.

In addition to the GulfTerra Merger, our business combinations and acquisitions during 2004 included the purchase of (i) an additional 16.7% ownership interest in Tri-States, (ii) an additional 10% ownership interest in Seminole, (iii) the remaining 33.3% ownership interest in BEF and (iv) certain assets located in Morgan s Point, Texas.

As a result of the final purchase price allocation for the GulfTerra Merger, we recorded $743.4 million of amortizable intangible assets and $387.1 million of goodwill. For additional information regarding these intangible assets, please read Note 13.

2005 Transactions

Our expenditures for business combinations and acquisitions during 2005 were $326.6 million, which included $8.3 million of purchase price adjustments relating to transactions that occurred prior to 2005.

In January 2005, we acquired indirect ownership interests in the Indian Springs Gathering System and Indian Springs natural gas processing plant for $74.9 million. In January and February 2005, we acquired an additional 46% of the ownership interests in Dixie for $68.6 million. In June 2005, we acquired additional indirect ownership interests in our Mid-America Pipeline System and Seminole Pipeline for $25 million. Also in June 2005, we acquired an additional 41.7% ownership interest in Belle Rose, which owns a NGL pipeline located in Louisiana, for $4.4 million. In July 2005, we purchased three underground NGL storage facilities and four propane terminals from Ferrellgas L.P. (Ferrellgas) for $145.5 million in cash. Dixie and Belle Rose became consolidated subsidiaries of ours in 2005 as a result of our acquisition of additional ownership interests in these two entities.

During 2005, we paid El Paso an additional $7 million in purchase price adjustments related to the GulfTerra Merger, the majority of which were related to merger-related financial advisory services and involuntary severance costs. In addition, we made various minor revisions to the GulfTerra Merger purchase price allocation before it was finalized on September 30, 2005.

Purchase Price Allocation for 2005 Transactions

Our 2005 acquisitions and post-closing purchase price adjustments were accounted for using the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated preliminary fair values as follows:

	Indian Springs	Dixie	Ferrellgas Assets	Other (2)	Total
Purchase price allocation:					
Assets acquired in business combination:					
Current assets	$ 252	$ (476)	$ 6,901	$ 2,217	$ 8,894
Property, plant and equipment, net	40,321	90,306	144,092	30,358	305,077
Investments in and advances to unconsolidated affiliates (1)		(36,279)		(10,017)	(46,296)
Intangible assets	19,095		109	1,009	20,213
Other assets		31,185		(3,694)	27,491
Total assets acquired	59,668	84,736	151,102	19,873	315,379
Liabilities assumed in business combination:					
Current liabilities	(118)	(2,758)	(5,580)	(4,761)	(13,217)
Long-term debt		(9,982)			(9,982)
Other long-term liabilities	(61)	(7,697)			(7,758)
Minority interest		(4,586)		11,603	7,017
Total liabilities assumed	(179)	(25,023)	(5,580)	6,842	(23,940)
Total assets acquired less liabilities assumed	59,489	59,713	145,522	26,715	291,439
Total consideration given	74,854	68,608	145,522	37,618	326,602
Goodwill	$ 15,365	$ 8,895	$ -	$ 10,903	$ 35,163

(1) Represents carrying value of our investment prior to consolidation.

(2) Includes purchase accounting adjustments for the GulfTerra Merger and preliminary purchase price allocations for the Mid-America, Seminole, Belle Rose and petrochemical pipeline transactions.

The purchase price allocations for our 2005 transactions are preliminary. We engaged an independent third-party business valuation expert to assess the fair value of tangible and intangible assets acquired in connection with the Indian Springs, Dixie, Belle Rose and Ferrellgas transactions. This information will assist us in developing final purchase price allocations for these transactions. Management developed its own fair value estimates of assets acquired and liabilities assumed in connection with the remaining 2005 transactions. Our preliminary values are subject to final valuation reports and additional information.

Selected Pro Forma Financial Information (Unaudited)

Our historical operating results were affected by business combinations and asset acquisitions during 2005 and 2004. Our most significant recent transaction was the GulfTerra Merger. Since the closing date of the GulfTerra Merger was September 30, 2004, our Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra prior to October 1, 2004. The effective closing date of our purchase of the South Texas midstream assets (Step Three of the GulfTerra Merger) was September 1, 2004. As a result, our Statements of Consolidated Operations and Comprehensive Income for 2004 include four months of earnings from the South Texas midstream assets. Our 2005 results already reflect the businesses we acquired in connection with the GulfTerra Merger; therefore, no pro forma adjustments are necessary for the 2005 period. Due to the immaterial nature of our other business combinations and acquisitions since 2004, our selected pro forma financial information includes only adjustments related to the GulfTerra Merger. Our pro forma basic and diluted earnings per unit for 2005 are practically the same as our actual basic and diluted earnings per unit for 2005.

The pro forma information presented in the following table is based on financial data available to us and includes certain estimates and assumptions made by our management. Our pro forma earnings data has been prepared as if the GulfTerra Merger transaction had been completed on January 1, 2004, as opposed to September 30, 2004. As a result, our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the GulfTerra Merger transactions actually occurred on this earlier date.

	For Year Ended December 31, 2004
Pro forma earnings data:	
Revenues	$ 9,615.1
Costs and expenses	$ 9,067.9
Operating income	$ 575.6
Net income	$ 33.5
Pro forma net income available to limited partners	$ 33.5
Basic and diluted earnings per unit, net of general partner interest:	
As reported basic and diluted units outstanding	74,667
Pro forma basic and diluted units outstanding	74,667
As reported basic and diluted net income per unit	$ 0.40
Pro forma basic and diluted net income per unit	$ 0.45

13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

		At December 31, 2005		At December 31, 2004	
	Gross Value	**Accum. Amort.**	**Carrying Value**	**Accum. Amort.**	**Carrying Value**
NGL Pipelines & Services:					
Shell Processing Agreement	$ 206,216	$ (56,157)	$ 150,059	$ (45,110)	$ 161,106
STMA and GulfTerra NGL Business customer relationships [(1)]	49,784	(7,829)	41,955	(1,606)	48,004
Markham NGL storage contracts [(1)]	32,664	(5,444)	27,220	(1,088)	31,576
Toca-Western contracts	31,229	(5,595)	25,634	(4,033)	27,196
Indian Springs customer relationships	16,439	(1,954)	14,485		
Mont Belvieu storage contracts	8,127	(929)	7,198	(697)	7,430
Other	10,804	(1,577)	9,227	(601)	7,651
Segment total	355,263	(79,485)	275,778	(53,135)	282,963
Onshore Natural Gas Pipelines & Services:					
San Juan Gathering System customer relationships [(1)]	331,311	(30,065)	301,246	(6,222)	325,089
Petal & Hattiesburg natural gas storage contracts [(1)]	100,499	(10,742)	89,757	(2,059)	98,440
Texas Intrastate pipeline customer relationships [(1)]	20,992	(2,538)	18,454	(531)	20,461
Other	4,996	(610)	4,386	(63)	2,277
Segment total	457,798	(43,955)	413,843	(8,875)	446,267
Offshore Pipelines & Services:					
Offshore pipeline & platform customer relationships [(1)]	205,845	(32,480)	173,365	(6,965)	198,880
Other	1,167		1,167		1,167
Segment total	207,012	(32,480)	174,532	(6,965)	200,047
Petrochemical Services:					
Mont Belvieu propylene fractionation contracts	53,000	(5,931)	47,069	(4,417)	48,583
Other	3,674	(1,270)	2,404	(791)	2,741
Segment total	56,674	(7,201)	49,473	(5,208)	51,324
Total all segments	$ 1,076,747	$ (163,121)	$ 913,626	$ (74,183)	$ 980,601

(1) Acquired in connection with the GulfTerra Merger in September 2004

The following table shows the amortization of our intangible assets by segment for the periods indicated:

	For Year Ended December 31,		
	2005	**2004**	**2003**
NGL Pipelines & Services	$ 26,350	$ 16,000	$ 12,977
Onshore Natural Gas Pipelines & Services	35,080	8,875	
Offshore Pipelines & Services	25,515	6,965	
Petrochemical Services	1,993	1,973	1,848
Total all segments	$ 88,938	$ 33,813	$ 14,825

Based on information currently available, we estimate that amortization expense associated with existing intangible assets will approximate $82.5 million in 2006, $77.2 million in 2007, $72.4 million in 2008, $67.5 million in 2009 and $63.7 million in 2010.

Our significant intangible assets can be classified into the following categories: (i) the Shell Processing Agreement, (ii) the intangible assets we acquired in connection with the GulfTerra Merger, and (iii) other customer relationships and contracts. The following is a description of these significant categories:

Shell Processing Agreement. The Shell Processing Agreement grants us the right to process Shell's (or its assignee s) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this intangible asset in connection with our 1999 acquisition of certain of Shell s midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

Intangible assets acquired in connection with GulfTerra Merger. We acquired customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by the GulfTerra and South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts that GulfTerra had entered into to provide storage services for natural gas and NGLs.

The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities and other industry factors. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (v) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

Other significant customer relationship and contract-based intangible assets. In January 2005, we acquired customer relationship intangible assets in connection with our purchase of indirect ownership interests in the Indian Springs natural gas gathering pipelines and processing assets. We are amortizing these intangible assets over a 19-year period, which is the expected life of the customers underlying resource bases.

In 2002, we acquired contract-based intangible assets in connection with the purchase of (i) a propylene fractionation facility and underground NGL and petrochemical storage caverns located in Mont Belvieu, Texas and (ii) a natural gas processing and NGL fractionation facility located in Louisiana (the Toca-Western contracts). In general, the values assigned to these intangible assets are being amortized on a straight-line basis over the estimated remaining economic life of underlying assets to which they relate, which ranged from 20 to 35 years at inception.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated:

	At December 31, 2005	2004
NGL Pipelines & Services		
GulfTerra Merger	$ 23,927	$ 24,026
Acquisition of Indian Springs natural gas processing assets	13,180	
Other	17,853	8,737
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	280,812	290,397
Acquisition of Indian Springs natural gas gathering assets	2,185	
Offshore Pipelines & Services		
GulfTerra Merger	82,386	62,348
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation assets	73,690	73,690
Totals	$ 494,033	$ 459,198

The goodwill resulting from the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership s assets and the industry relationships that each possessed. In addition, we expected that various operating synergies would develop (such as reduced general and administrative costs and interest savings) that could improve financial results of the merged entities. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions, especially the deepwater regions of the Gulf of Mexico, offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our purchase of propylene fractionation assets from Diamond-Koch in February 2002. We also recorded goodwill in connection with our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing assets in January 2005.

14. Debt Obligations

Our consolidated debt consisted of the following at the dates indicated:

	December 31, 2005	2004
Parent Company debt obligations:		
$525 Million Credit Facility, amended and restated January 2006 (1)	$ 134,500	
Operating Partnership debt obligations:		
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (2)		$ 242,229
Multi-Year Revolving Credit Facility, variable rate, due October 2010	490,000	321,000
Seminole Notes, 6.67% fixed-rate, repaid December 2005		15,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005		350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015 (3)	250,000	
Senior Notes J, 5.75% fixed-rate, due March 2035 (4)	250,000	
Senior Notes K, 4.950% fixed-rate, due June 2010 (5)	500,000	
Enterprise Products GP related party obligation:		
$370 Million Note to Dan Duncan LLC, 6.25% fixed-rate, repaid August 2005		366,433
Dixie Revolving Credit Facility, variable rate, due June 2007	17,000	
Debt obligations assumed from GulfTerra	5,067	6,469
Total principal amount	5,000,567	4,655,131
Other, including unamortized discounts and premiums and changes in fair value (6)	(32,287)	(7,462)
Subtotal long-term debt	4,968,280	4,647,669
Less current maturities of debt (7)		(18,450)
Long-term debt	$ 4,968,280	$ 4,629,219
Standby letters of credit outstanding	$ 33,129	$ 139,052

(1) The parent company amended and restated this credit facility in January 2006 resulting in a new $200 Million Credit Facility.

(2) Enterprise Products Partners used the proceeds from its February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility.

(3) Senior Notes I were issued at 99.379% of their face amount in February 2005.

(4) Senior Notes J were issued at 98.691% of their face amount in February 2005.

(5) Senior Notes K were issued at 99.834% of their face amount in June 2005.

(6) The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. The December 31, 2004 amount includes $1.8 million related to fair value hedges and $9.2 million in net unamortized discounts.

(7) In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," long-term and current maturities of debt at December 31, 2004, reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Facility using proceeds from an equity offering completed by Enterprise Products Partners in February 2005.

Letters of credit

At December 31, 2005, we had $33.1 million in standby letters of credit outstanding, which were issued under the Operating Partnership s Multi-Year Revolving Credit Facility. At December 31, 2004, we had $139.1 million of standby letters of credit outstanding, of which $115.1 million were issued under a letter of credit facility associated with our Independence Trail capital project. The decrease in letters of credit outstanding since 2004 is primarily due to the expiration of the Independence Trail letter of credit facility in October 2005.

Parent company debt obligation

$525 Million Credit Facility. On August 29, 2005, the parent company entered into a $525 million credit facility consisting of a $475 million term loan and a $50 million revolving credit facility. The parent company borrowed $525 million under this facility to repay (i) $365 million of indebtedness owed by Enterprise Products GP to an affiliate of EPCO and (ii) $160 million of debt the parent company assumed from EPCO. The $365 million owed by Enterprise Products GP was originally incurred to purchase a 50% interest in the general partner of GulfTerra from El Paso in September 2004. The parent company assumed the $160 million in debt from an affiliate of EPCO in connection with EPCO s contribution of net assets to the parent company in August 2005.

The parent company used the net proceeds from its initial public offering in August 2005 to repay $350.5 million owed under this credit facility. At December 31, 2005, $124.5 million was outstanding under the term loan and $10 million under the revolving credit portion of this agreement. These amounts were originally set to mature in February 2006. In January 2006, the parent company amended and restated its $525 Million Credit Facility with the result being a new $200 Million Credit Facility. See Note 26 for additional information regarding this subsequent event.

Enterprise Products GP related party obligation

$370 Million Note Payable. In September 2004, Enterprise Products GP borrowed $370 million from an affiliate of EPCO to fund the cash portion of consideration paid to El Paso for a 50% membership interest in GulfTerra's general partner. This related party promissory note bore a fixed-interest rate of 6.25%. Installment payments of $6.6 million were due quarterly from November 2004 through November 2019. Under terms of the note agreement, we were allowed to defer up to $13.2 million of scheduled quarterly installment payments at any time, except that all principal and accrued interest must be repaid by the November 2019 maturity date. On August 29, 2005, this note payable was repaid in full using borrowings under the parent company s $525 Million Credit Facility.

Enterprise Products Partners-Subsidiary guarantor relationships

At December 31, 2005, Enterprise Products Partners acts as guarantor of the debt obligations of its Operating Partnership, with the exception of the Dixie revolving credit facility and the senior subordinated notes of GulfTerra. If the Operating Partnership were to default on any debt guaranteed by Enterprise Products Partners, Enterprise Products Partners would be responsible for full repayment of that obligation.

The Operating Partnership s senior indebtedness is structurally subordinated to and ranks junior in right of payment to the indebtedness of GulfTerra and Dixie. This subordination feature exists only to the extent that the repayment of debt incurred by GulfTerra and Dixie is dependent upon the assets and operations of these two entities. The Dixie revolving credit facility is an unsecured obligation of Dixie (of which we own 65.9% of its capital stock). The senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

Operating Partnership debt obligations

364-Day Acquisition Credit Facility. In August 2004, the Operating Partnership entered into a $2.25 billion 364-Day Acquisition Credit Facility, which was used to provide interim financing for certain purchase transactions associated with the GulfTerra Merger and the refinancing of substantially all of GulfTerra s then outstanding debt. The Operating Partnership repaid approximately $2 billion of this indebtedness in October 2004 using proceeds from its issuance of Senior Notes E, F, G and H. In February 2005, the Operating Partnership repaid the remaining balance using proceeds from Enterprise Products Partners February 2005 common unit offering and terminated the facility.

Multi-Year Revolving Credit Facility. In August 2004, the Operating Partnership entered into a five-year multi-year revolving credit agreement in connection with the completion of the GulfTerra Merger. In October 2005, the borrowing capacity under this credit agreement was increased from $750 million to $1.25 billion, with the possibility that the borrowing capacity could be further increased to $1.4 billion (subject to certain conditions). In addition, the maturity date for debt outstanding under the facility was extended from September 2009 to October 2010. The Operating Partnership may make up to two requests for one-year extensions of the maturity date (subject to certain conditions). There is no limit on the amount of standby letters of credit that can be outstanding under the amended facility.

The Operating Partnership s borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise Products GP. Enterprise Products Partners has guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate.

This revolving credit agreement contains various covenants related to Enterprise Products Partners' ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires Enterprise Products Partners to satisfy certain financial covenants at the end of each fiscal quarter. The Multi-Year Revolving Credit Facility restricts the Operating Partnership s ability to pay cash distributions to us if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

Seminole Notes. Seminole Pipeline Company (Seminole), a majority-owned subsidiary, made the final $15 million payment on its indebtedness in December 2005.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, the Operating Partnership entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation (MBFC). This loan is subject to a make-whole redemption right and is guaranteed by Enterprise Products Partners through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility.

The indenture agreement for this loan contains an acceleration clause whereby if the Operating Partnership's credit rating by Moody's declines below Baa3 in combination with its credit rating at Standard & Poor's remaining at BB+ or lower, the $54 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, Enterprise Products Partners would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

Senior Notes A through K. These fixed-rate notes are unsecured obligations of the Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. The Operating Partnership s borrowings under these notes are non-recourse to Enterprise Products GP. Enterprise Products Partners has guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee, which is non-recourse to Enterprise Products GP.

Senior Notes A through D are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict Enterprise Products Partners' ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. The remainder of the Senior Notes (E through K) are also subject to similar covenants.

Senior Notes E, F, G, and H were issued as private placement debt in September 2004 and generated an aggregate $2 billion in proceeds, which were used to repay amounts borrowed under the 364-Day Acquisition Credit Facility. Senior Notes E through H were exchanged for registered debt securities in March 2005.

Senior Notes I and J were issued as private placement debt in February 2005 and generated an aggregate $500 million in proceeds, which were used to repay $350 million due under Senior Notes A (which matured in March 2005) and the remainder for general partnership purposes, including the temporary repayment of amounts then outstanding under the Multi-Year Revolving Credit Facility. Senior Notes I and J were exchanged for registered debt securities in August 2005.

Senior Notes K were issued as registered securities in June 2005 and generated $500 million in proceeds, which were used for general partnership purposes, including the temporary repayment of amounts then outstanding under the Multi-Year Revolving Credit Facility. Senior Notes K were issued under the $4 billion universal shelf registration statement Enterprise Products Partners filed in March 2005.

Dixie Revolving Credit Facility

As a result of acquiring a controlling interest in Dixie in February 2005, we began consolidating the financial statements of Dixie with those of our own. Dixie s debt obligations consist of a senior unsecured revolving credit facility having a borrowing capacity of $28 million.

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the Prime Rate or (b) the Federal Funds Rate by ½%.

This revolving credit agreement contains various covenants related to Dixie s ability to incur certain indebtedness; grant certain liens; enter into merger transactions; and make certain investments. The loan agreement also requires Dixie to satisfy a minimum net worth financial covenant. The revolving credit agreement restricts Dixie s ability to pay cash dividends to us and its other stockholders if a default or an event of default (as defined in the credit agreement) has occurred and its continuing at the time such dividend is scheduled to be paid.

Debt Obligations assumed from GulfTerra

Senior and Senior Subordinated Notes. Upon completion of the GulfTerra Merger, we recorded in consolidation $921.5 million of GulfTerra s then outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased by the Operating Partnership in October 2004 pursuant to its tender offers for such debt. The Operating Partnership financed these purchases using borrowings under its 364-Day Acquisition Credit Facility. The noteholders also approved (as a condition to accepting the tender offers) amendments that removed all restrictive covenants governing the GulfTerra notes.

At December 31, 2004, $6.5 million in principal amount of these obligations remained outstanding. During 2005, we redeemed an additional $1.4 million of this assumed debt. The $5.1 million in principal remaining outstanding at December 31, 2005 bears fixed-rate interest of 8.5% and matures in June 2010.

Petal Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. (Petal), one of our wholly owned subsidiaries, borrowed $52 million from the MBFC. Concurrently, the MBFC sold $52 million in Industrial Development Bonds to another of our wholly owned subsidiaries. Petal had the option to repay its MBFC loan without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. In August 2005, Petal exercised its option to repay the loan agreement and the $52 million in Industrial Development Bonds were redeemed and retired.

Prior to redemption, we netted the Petal MBFC loan payable against the Industrial Development Bonds receivable and also the related interest payable and receivable amounts on our balance sheet. Additionally, we netted the interest expense and interest income amounts attributable to these instruments on our statements of consolidated operations. This presentation was in accordance with the provisions of FIN 39, "*Offsetting of Amounts Related to Certain Contracts*," and SFAS 140, "*Accounting for Transfers* *and Servicing of Financial Assets and Extinguishments of Liabilities*," since we had the ability and intent to offset these items.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2005 and 2004.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our significant consolidated variable-rate debt obligations during 2005.

	Range of interest rates paid	**Weighted-average interest rate paid**
Parent Company s Revolving Credit Facility - $50 MM	5.91% to 7.50%	6.23%
Parent Company s Revolving Credit Facility - $475 MM	5.91% to 7.50%	6.30%
Enterprise Products Partners' 364-Day Acquisition Credit Facility	3.25% to 3.40%	3.35%
Enterprise Products Partners' Multi-Year Revolving Credit Facility	3.22% to 7.00%	4.25%
Dixie Revolving Credit Facility	3.66% to 4.67%	4.12%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next 5 years and in total thereafter.

2006	None.
2007	$ 517,000
2008	None.
2009	634,500
2010	1,049,067
Thereafter	2,800,000
Total scheduled principal payments	$ 5,000,567

Joint venture debt obligations

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2005, (ii) total debt of each unconsolidated affiliate at December 31, 2005, on a 100% basis to the joint venture, and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2006	2007	2008	2009	2010	After 2010
Cameron Highway	50.0%	$ 415,000			$ 25,000	$ 25,000	$ 50,000	$ 315,000
Poseidon	36.0%	95,000			95,000			
Evangeline	49.5%	30,650	$ 5,000	$ 5,000	5,000	5,000	10,650	
Total		$ 540,650	$ 5,000	$ 5,000	$ 125,000	$ 30,000	$ 60,650	$ 315,000

The credit agreements of our joint ventures contain various affirmative and negative covenants, including financial covenants. Our joint ventures were in compliance with all such covenants at December 31, 2005. The credit agreements of our joint ventures restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and its continuing at the time such dividend is scheduled to be paid.

In March 2005, we contributed $72 million to Deepwater Gateway to assist in the repayment of its $144 million term loan. Our joint venture partner in Deepwater Gateway also contributed $72 million.

Deepwater Gateway used funds borrowed under its term loan to fund a substantial portion of the cost to construct the Marco Polo platform and related facilities.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2005:

Cameron Highway. In July 2003, Cameron Highway entered into a $325 million project loan facility to finance a substantial portion of the cost to construct its crude oil pipeline. In June 2005, Cameron Highway executed a new term loan agreement with a total credit commitment of $415 million and borrowed the full amount, which was used to repay principal amounts outstanding under the project loan facility and to make $95 million in cash distributions to its partners. We received a partial return of our investment in Cameron Highway of $47.5 million in connection with this special distribution. In connection with this refinancing, Cameron Highway incurred $22 million in one-time cash make-whole premiums and related fees and non-cash charges.

In December 2005, Cameron Highway issued $415 million of private placement, non-recourse senior secured notes due December 2017. Proceeds from the issuance of these senior secured notes were used to repay the $415 million term loan that Cameron Highway entered into during June 2005. The senior secured notes were issued in two series - $365 million of Series A notes, which have a fixed-rate interest of 5.86%, and $50 million of Series B notes, which have a variable-rate interest based on a Eurodollar rate plus 1%. At December 31, 2005, the variable interest rate charged under the Series B notes was 4.52%.

The notes are secured by (i) mortgages on and pledges of substantially all of the assets of Cameron Highway, (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of ours that serves as the operator of the Cameron Highway Oil Pipeline, (iii) pledges by us and our joint venture partner in Cameron Highway of our 50% partnership interests in Cameron Highway, and (iv) letters of credit in an initial amount of $18.4 million each issued by the Operating Partnership and an affiliate of our joint venture partner. Except for the foregoing, the noteholders do not have any recourse against our assets or any of our subsidiaries under the note purchase agreement.

Poseidon. Poseidon has entered into a $170 million revolving credit facility that matures in January 2008. The interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon s total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon s assets. The variable interest rates charged on this debt at December 31, 2005 and 2004 were 5.34% and 4.58%, respectively.

Evangeline. At December 31, 2005, long-term debt for Evangeline consisted of (i) $23.2 million in principal amount of 9.9% fixed-rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline s property, plant and equipment; proceeds from a gas sales contract; and by a debt service reserve requirement. Scheduled principal repayments on the Series B notes are $5 million annually through 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. Variable rate interest accrues on the subordinated note at a Eurodollar rate plus ½%. The variable interest rates charged on this note at December 31, 2005 and 2004 were 3.58% and 1.73%, respectively. Accrued interest payable related to the subordinated note was $7.1 million and $6.6 million at December 31, 2005 and 2004.

15. Partners Equity

General

Enterprise GP Holdings L.P. is a Delaware limited partnership that was formed in April 2005 to become the sole member of Enterprise Products GP, which is the general partner of Enterprise Products Partners. Enterprise GP Holdings L.P. is owned 99.99% by its limited partners and 0.01% by EPE Holdings. EPE Holdings is owned 100% by Dan Duncan, LLC, which is wholly-owned by Dan L. Duncan. In connection with the August 2005 contribution of net assets by affiliates of EPCO to Enterprise GP Holdings L.P. in August 2005 (see Note 1), affiliates of EPCO received 74,667,332 of units of Enterprise GP Holdings L.P.

The units of Enterprise GP Holdings L.P. represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under the First Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement") of Enterprise GP Holdings L.P.

Capital accounts, under the Partnership Agreement, are maintained for the general partner and the limited partners of Enterprise GP Holdings L.P. The capital account provisions of the Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements. Earnings and cash distributions are allocated to the partners of Enterprise GP Holdings L.P. in accordance with their respective percentage interests.

In August 2005, Enterprise GP Holdings L.P. completed its initial public offering of 14,216,784 units (including an over-allotment amount of 1,616,784 units) at an offering price of $28.00 per unit. Total net proceeds from the sale of these units was approximately $373 million after deducting applicable underwriting discounts, commissions, structuring fees and other offering expenses of $25.6 million. The net proceeds from this initial public offering were used to reduce debt outstanding under the $525 Million Credit Facility. For additional information regarding this credit facility, please see Note 14.

Unit History

The following table details the outstanding balance of the units of Enterprise GP Holdings L.P. for the periods and at the dates indicated:

Units issued to affiliates of EPCO in connection with the contribution of net assets in August 2005 (the sponsor units)	74,667,332
Units issued in August 2005 in connection with initial public offering	14,216,784
Balance, December 31, 2005	88,884,116

As described in Note 1, the consolidated financial information presented under Item 8 of this annual report for periods prior to August 2005 is based on the consolidated financial information of the parent company's predecessor, Enterprise Products GP. Our earnings per unit amounts for periods prior to our initial public offering in August 2005 assume that affiliates of EPCO owned the sponsor units during those periods.

Accumulated Other Comprehensive Income (Loss)

The following table summarizes transactions affecting our accumulated other comprehensive income (loss) since December 31, 2002.

		Interest Rate Fin. Instrs.		
	Commodity Financial Instruments	Treasury Locks	Forward-Starting Interest Rate Swaps	Accumulated Other Comprehensive Income (Loss) Balance
Balance, December 31, 2002		$ (3,560)		$ (3,560)
Reclassification of change in fair value of treasury locks		3,560		3,560
Gain on settlement of treasury locks		5,354		5,354
Reclassification of gain on settlement of treasury locks to interest expense		(364)		(364)
Balance, December 31, 2003		4,990		4,990
Gain on settlement of forward-starting interest rate swaps			$ 104,531	104,531
Loss on settlement of forward-starting interest rate swaps			(85,126)	(85,126)
Change in fair value of commodity financial instrument	$ 1,434			1,434
Reclassification of gain on settlement of interest rate financial instruments		(418)	(857)	(1,275)
Balance, December 31, 2004	1,434	4,572	18,548	24,554
Change in fair value of commodity financial instruments	(1,434)			(1,434)
Reclassification of gain on settlement of interest rate financial instruments		(445)	(3,603)	(4,048)
Balance, December 31, 2005	$ -	$ 4,127	$ 14,945	$ 19,072

During the first quarter of 2005, we reclassified into income a $1.4 million gain related to a commodity cash flow hedge we acquired in connection with the GulfTerra Merger. This gain resulted from an increase in fair value of the underlying financial instrument from the value recorded for the commodity cash flow hedge at September 30, 2004. In 2006, we expect to reclassify $4.3 million of accumulated other comprehensive income that was generated by treasury lock and forward-starting interest rate swap transactions to reduce interest expense.

16. Distributions to Partners

The parent company s cash distribution policy is consistent with the terms of its Partnership Agreement, which requires it to distribute its available cash (as defined in our Partnership Agreement) to its partners no later than 50 days after the end of each fiscal quarter. The quarterly cash distributions are not cumulative. As a result, if distributions on the parent company s units are not paid at the targeted levels, unitholders will not be entitled to receive such payments in the future.

The parent company s cash generating assets currently consist entirely of its partnership interests in Enterprise Products Partners, from which it receives quarterly cash distributions. At December 31, 2005, the parent company s assets consisted of the following partnership interests in Enterprise Products Partners:

a 100% ownership interest of Enterprise Products GP, which owns a 2% general partner interest in Enterprise Products Partners that entitles Enterprise Products GP to receive 2% of the cash distributed by Enterprise Products Partners;

the incentive distribution rights associated with Enterprise Products GP's general partner interest in Enterprise Products Partners, which entitle Enterprise Products GP to receive increasing percentages of the cash distributed by Enterprise Products Partners (up to a maximum of 25% of Enterprise Products Partners' quarterly distributions that exceed $0.3085 per unit); and

13,454,498 common units of Enterprise Products Partners, representing an approximate 3.4% limited partner interest in Enterprise Products Partners.

Since the parent company s primary source of operating cash flow currently consists of cash distributions from Enterprise Products Partners, the amount of distributions it is able to make to its unitholders may fluctuate based on the level of distributions Enterprise Products Partners makes to its partners. If Enterprise Products Partners does not have sufficient available cash from Operating Surplus (as defined in Enterprise Products Partners' Partnership Agreement), or if the Operating Partnership is not able to satisfy certain financial covenants in accordance with its credit agreements, Enterprise Products Partners will be restricted from making distributions to its partners.

The primary restriction on the Operating Partnership s ability to make cash distributions to Enterprise Products Partners and hence to us, is a financial covenant in the Operating Partnership s Multi-Year Revolving Credit Facility that requires the Operating Partnership to maintain capital accounts of at least $4 billion. At December 31, 2005, the Operating Partnership s equity accounts totaled $5.7 billion. In addition, if the parent company is not able to satisfy certain financial covenants in accordance with its $525 Million Credit Facility, it will be restricted from making distributions to its partners. As of December 31, 2005, the parent company and Enterprise Products Partners are in compliance with the various covenants of our debt agreements.

The following table presents the parent company s quarterly cash distribution rates per unit paid to common unitholders since its initial public offering in August 2005 and the related record and distribution payment dates.

	Cash Distribution History		
	Distribution per Unit	**Record Date**	**Payment Date**
3rd Quarter 2005	$0.2650	Oct. 31, 2005	Nov. 10, 2005
4th Quarter 2005	$0.2800	Jan. 31, 2006	Feb. 10, 2006

The quarterly cash distribution of the parent company that was paid on November 10, 2005, was prorated to $0.092 per common unit based on the 32-day period that elapsed from the closing of its initial public offering on August 30, 2005 to September 30, 2005. The declared distribution rate for the third quarter of 2005 was $0.265 per common unit.

17. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (i) depreciation and amortization expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues and operating costs and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

We have historically included equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be suppliers of raw materials or consumers of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system through a number of ways, including an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we earn revenues based on volume or an ownership of products such as NGLs.

Many of our equity investees are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate.

Our consolidated revenues were earned in the United States and derived from a wide customer base. Currently, our plant-based operations are located primarily in Texas, Louisiana, Mississippi and New Mexico. Our natural gas, NGL and crude oil pipelines are in a number of regions of the United States including the Gulf of Mexico offshore Texas and Louisiana; the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and certain regions of the central and western United States. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net carrying value of facilities and projects that contribute to the gross operating margin of a particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from the segment asset totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to each segment based on the classification of the assets to which they relate.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	Year Ended December 31, 2005	2004	2003
Revenues [1]	$ 12,256,959	$ 8,321,202	$ 5,346,431
Less: Operating costs and expenses [1]	(11,546,225)	(7,904,336)	(5,046,777)
Add: Equity in income (loss) of unconsolidated affiliates [1]	14,548	52,787	(13,960)
Depreciation and amortization in operating costs and expenses [2]	413,441	193,734	115,643
Retained lease expense, net in operating expenses allocable to us and minority interest [3]	2,112	7,705	9,094
Gain on sale of assets in operating costs and expenses [2]	(4,488)	(15,901)	(16)
Total segment gross operating margin	$ 1,136,347	$ 655,191	$ 410,415

(1) These amounts are taken from our Statements of Consolidated Operations and Comprehensive Income.

(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

(3) These non-cash expenses represent the value of the operating leases contributed by EPCO to us for which EPCO has retained the cash payment obligation (i.e., the retained leases). The value of the retained leases contributed directly to us is shown on our Statements of Consolidated Cash Flows under the line item titled Operating lease expense paid by EPCO. That portion of the value contributed by a minority interest holder is a component of Contributions from minority interests as shown in the financing activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our measurement of total segment gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	Year Ended December 31, 2005	2004	2003
Total segment gross operating margin	$ 1,136,347	$ 655,191	$ 410,415
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation and amortization in operating costs and expenses	(413,441)	(193,734)	(115,643)
Retained lease expense, net in operating costs and expenses	(2,112)	(7,705)	(9,094)
Gain on sale of assets in operating costs and expenses	4,488	15,901	16
General and administrative costs	(64,194)	(47,264)	(39,164)
Consolidated operating income	661,088	422,389	246,530
Other expense	(243,581)	(159,459)	(134,297)
Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 417,507	$ 262,930	$ 112,233

Information by segment, together with reconciliations to the consolidated totals, is presented in the following table:

	Operating Segments						
	Offshore Pipelines & Services	Onshore Natural Gas Pipelines & Services	NGL Pipelines & Services	Petrochemical Services	Non-Segmt. Other	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:							
Year ended December 31, 2005	$110,100	$1,198,320	$9,006,730	$1,587,037			$11,902,187
Year ended December 31, 2004	32,168	541,529	5,553,895	1,389,460			7,517,052
Year ended December 31, 2003		344,611	3,654,577	782,999			4,782,187
Revenues from related parties:							
Year ended December 31, 2005	696	337,282	16,689	105			354,772
Year ended December 31, 2004	535	253,194	534,279	16,142			804,150
Year ended December 31, 2003		227,973	325,377	10,894			564,244
Intersegment and intrasegment revenues:							
Year ended December 31, 2005	1,353	41,576	3,334,763	346,458		$(3,724,150)	
Year ended December 31, 2004	358	21,436	2,077,871	249,758		(2,349,423)	
Year ended December 31, 2003		3,975	1,143,595	186,672		(1,334,242)	
Total revenues:							
Year ended December 31, 2005	112,149	1,577,178	12,358,182	1,933,600		(3,724,150)	12,256,959
Year ended December 31, 2004	33,061	816,159	8,166,045	1,655,360		(2,349,423)	8,321,202
Year ended December 31, 2003		576,559	5,123,549	980,565		(1,334,242)	5,346,431
Equity in income (loss) in unconsolidated affiliates:							
Year ended December 31, 2005	6,125	2,384	5,553	486			14,548
Year ended December 31, 2004	8,859	772	9,898	1,233	$32,025		52,787
Year ended December 31, 2003	5,561	131	7,842	(27,441)	(53)		(13,960)
Gross operating margin by individual business segment and in total:							
Year ended December 31, 2005	77,505	353,076	579,706	126,060			1,136,347
Year ended December 31, 2004	36,478	90,977	374,196	121,515	32,025		655,191
Year ended December 31, 2003	5,561	18,345	310,677	75,885	(53)		410,415
Segment assets:							
At December 31, 2005	632,222	3,622,318	3,075,048	504,841		854,595	8,689,024
At December 31, 2004	648,181	3,729,650	2,753,934	469,327		230,375	7,831,467
Investments in and advances to unconsolidated affiliates (see Note 11):							
At December 31, 2005	316,844	4,644	130,376	20,057			471,921
At December 31, 2004	319,463	5,251	173,883	20,567			519,164
Intangible Assets (see Note 13):							
At December 31, 2005	174,532	413,843	275,778	49,473			913,626
At December 31, 2004	200,047	446,267	282,963	51,324			980,601
Goodwill (see Note 13):							
At December 31, 2005	82,386	282,997	54,960	73,690			494,033
At December 31, 2004	62,348	290,397	32,763	73,690			459,198

In general, our historical operating results and/or financial position have been affected by numerous acquisitions since 2002. Our most significant transaction to date was the GulfTerra Merger, which was completed in September 2004. The value of total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The operating results of entities and assets we acquire are included in our financial results prospectively from their purchase dates.

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 67% of total consolidated revenues for each of 2005 and 2004 and 68% of total consolidated revenues for 2003. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11%, 13% and 12% of total consolidated revenues for 2005, 2004 and 2003, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13%, 10% and 11% of total consolidated revenues for 2005, 2004 and 2003, respectively.

18. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For Year Ended December 31, 2005	2004	2003
Revenues from consolidated operations			
EPCO and affiliates	$ 311	$ 2,697	$ 4,241
Shell		542,912	293,109
Unconsolidated affiliates	354,461	258,541	266,894
Total	$ 354,772	$ 804,150	$ 564,244
Operating costs and expenses			
EPCO and affiliates	$ 293,134	$ 203,100	$ 149,915
Shell		725,420	607,277
Unconsolidated affiliates	23,563	37,587	43,752
Total	$ 316,697	$ 966,107	$ 800,944
General and administrative expenses			
EPCO and affiliates	$ 41,054	$ 29,307	$ 28,716
Interest Expense			
EPCO and affiliates	$ 15,306	$ 5,849	

Historically, Shell was considered a related party because it owned more than 10% of the limited partner interests of Enterprise Products Partners and, prior to 2003, held a 30% membership interest in Enterprise Products GP. As a result of Shell selling a portion of its limited partner interests in Enterprise Products Partners to third parties, Shell owned less than 10% of the common units of our subsidiary at the beginning of 2005. Shell sold its 30% interest in Enterprise Products GP to an affiliate of EPCO in September 2003. As a result of Shell's reduced equity interest in Enterprise Products Partners and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party in January 2005.

Relationship with EPCO and its other affiliates

General. We have an extensive and ongoing relationship with EPCO and its other affiliates, which include the following significant entities:

EPCO and its private company subsidiaries;
EPE Holdings, the general partner of the parent company;
the Employee Partnership; and
TEPPCO Partners, L.P. (TEPPCO) and its general partner (TEPPCO GP), which are controlled by affiliates of EPCO.

Unless noted otherwise, our agreements with EPCO are not the result of arm s length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Enterprise Products Partners was formed in 1998 to own and operate certain NGL assets contributed to it by EPCO. EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of EPE Holdings and Enterprise Products GP. Mr. Duncan owns 50.4% of the voting stock of EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan s family.

At December 31, 2005, EPCO and its affiliates beneficially owned 76,890,603 (or 86.5%) of the parent company s outstanding units and 144,055,494 (or 36.2%) of Enterprise Products Partners common units. In January 2005, an affiliate of EPCO acquired 13,454,498 common units of Enterprise Products Partners and a 9.9% membership interest in Enterprise Products GP from El Paso for approximately $425 million in cash. As a result of this transaction and until August 2005, EPCO and certain of its affiliates owned 100% of the membership interests of Enterprise Products GP. An affiliate of EPCO is the sole member of EPE Holdings.

In August 2005, affiliates of EPCO contributed their member interests in Enterprise Products GP and the 13,454,498 common units of Enterprise Products Partners they acquired from El Paso to the parent company. As a result of this contribution, the parent company is the sole member of Enterprise Products GP and owns 3.4% of the limited partner interests of Enterprise Products Partners.

The principal business activity of EPE Holdings and Enterprise Products GP is to act as the managing partners of Enterprise GP Holdings L.P. and Enterprise Products Partners L.P., respectively. The executive officers and certain of the directors of EPE Holdings and Enterprise Products GP are employees of EPCO.

Apart from the rights Enterprise Products GP owns with respect to its general partner interest in Enterprise Products Partners, Enterprise Products GP does not receive any compensation for services provided to Enterprise Products Partners. Likewise, EPE Holdings does not receive any compensation for services provided to the parent company. During 2005, 2004 and 2003, Enterprise Products GP received $76.8 million, $40.4 million and $25.7 million, respectively, of cash distributions from Enterprise Products Partners in connection with its general partner interest. The foregoing distributions for 2005, 2004 and 2003 include $63.9 million, $32.4 million and $19.7 million, respectively, of incentive distributions.

We, EPE Holdings, Enterprise Products Partners, and Enterprise Products GP are separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO depends on the cash distributions it receives from us, Enterprise Products Partners and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received a combined $243.9 million, $189.8 million and $176.8 million in cash distributions from us and Enterprise Products Partners during 2005, 2004 and 2003, respectively.

The ownership interests in us and Enterprise Products Partners that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an EPCO affiliate. EPCO s credit facility contains customary and other events of default relating to EPCO and certain affiliates, including us, Enterprise Products Partners and TEPPCO. In the event of a default under this credit facility, a change in control of us or Enterprise Products Partners could occur.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. During 2005, we paid this affiliate $17.6 million for such services. In addition, We buy from and sell certain NGL products to another affiliate of EPCO at market-related prices in the normal course of business. During 2005, our revenues from this affiliate were $0.3 million and our purchases from this affiliate were $61 million.

We also lease office space in various buildings from affiliates of EPCO related to our corporate headquarters in Houston, Texas. During 2005, our operating lease expense recorded in connection with these agreements was $3.3 million. The rental rates in these agreements approximate market rates.

Relationship with TEPPCO. In February 2005, an affiliate of EPCO acquired 100% of the membership interests of TEPPCO GP, the general partner of TEPPCO and 2,500,000 common units of TEPPCO for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. In June 2005, the employees of TEPPCO became EPCO employees. Enterprise Products Partners paid $17.2 million to TEPPCO during 2005 for NGL pipeline transportation and storage services. In addition, certain directors of Enterprise Products GP and Enterprise GP Holdings (Messrs. Bachmann, Creel and Fowler) were elected as additional directors of TEPPCO GP in February 2006.

In March 2005, the Bureau of Competition of the FTC delivered written notice to EPCO s legal advisor that it was conducting a non-public investigation to determine whether EPCO s acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with EPCO s purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and we intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets.

In February 2006, we and TEPPCO entered into a letter of intent related to the formation of a joint venture to expand TEPPCO s Jonah Gas Gathering System (the Jonah system) located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d. The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006. The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and the general partner of Enterprise Products Partners, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d. We expect this expansion to be completed in mid-2006.

Employee Partnership. In connection with the initial public offering of the parent company, EPCO formed the Employee Partnership to serve as an incentive arrangement for certain employees of EPCO through a profits interest in the Employee Partnership. EPCO serves as the general partner of the Employee Partnership. In connection with the closing of our initial public offering, EPCO Holdings, Inc., a wholly owned subsidiary of EPCO, borrowed $51 million under its credit facility and contributed the borrowings to its wholly-owned subsidiary, Duncan Family Interests, Inc. (Duncan Family Interests), which, in turn, contributed $51 million to the Employee Partnership as a capital contribution with respect to its Class A limited partner interest. The Employee Partnership used the contributed funds to purchase 1,821,428 units directly from us at the initial public offering price. Certain EPCO employees, including all of EPE Holdings and Enterprise Products GP s executive officers other than Dan L. Duncan, have been issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of the Employee Partnership, the Employee Partnership will terminate at the earlier of five years following the closing of our initial public offering or a change in control of us or our general partner. The Employee Partnership has the following material terms with respect to distributions:

Distributions of Cashflow each quarter, 100% of the distributions from units held by the Employee Partnership will be distributed to Duncan Family Interests until it has received the Class A preferred return (as defined below), and any remaining distributions from the Employee Partnership will be distributed to the Class B limited partners. The Class A preferred return will equal 1.5625% per quarter, or 6.25% per annum, of Duncan Family Interest s capital base. Duncan Family Interest s capital base will equal $51 million, increased by any unpaid Class A preferred return from prior periods, and decreased by any distributions of sale proceeds to Duncan Family Interests as described below.

Liquidating Distributions Upon liquidation of the Employee Partnership, units having a fair market value equal to Duncan Family Interest s capital base will be distributed to Duncan Family

Interests, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

Sale Proceeds If the Employee Partnership sells any units, the sale proceeds will be distributed to Duncan Family Interests and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in the Employee Partnership that are owned by EPCO employees are subject to forfeiture if the participating employee s employment with EPCO and its affiliates is terminated prior to the fifth anniversary of the closing of our initial public offering, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in the Employee Partnership will also lapse upon certain change of control events.

We and our general partner will not reimburse EPCO, the Employee Partnership or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to the Employee Partnership or the contribution of $51 million to the Employee Partnership or the purchase of the units by the Employee Partnership.

For the period that the Employee Partnership was in existence during 2005, EPCO accounted for this stock-based compensation arrangement using APB 25. Under APB 25, the value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights. EPCO s non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of each employee s services. During 2005, we recorded $2 million of non-cash compensation expense associated with the Employee Partnership. For additional information regarding our equity awards, see Note 5.

Administrative Services Agreement. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (ASA). We and our general partner, Enterprise Products Partners and its general partner, and TEPPCO and its general partner are parties to the ASA. The significant terms of the ASA are as follows:

EPCO will provide selling, general, administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

EPCO has allowed us to participate as named insureds in its overall insurance program with the associated costs being charged to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the retained leases). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our operating costs and expenses for 2005, 2004 and 2003 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for 2005 and 2004 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity s business and affairs).

During 2003, our reimbursement to EPCO for administrative services was facilitated by the payment of a fixed-fee for costs associated with employees and functions present at our initial public offering in 1998 and on an actual basis for costs associated with employees hired in connection with our expansion activities up to that time. To the extent that the fixed-fee portion of this reimbursement method was less than EPCO s actual charges for such employees, we recorded a non-cash related party expense for the difference.

The ASA addresses potential conflicts that may arise among Enterprise Products Partners, Enterprise Products GP, Enterprise GP Holdings L.P., EPE Holdings and the EPCO Group, which includes EPCO and its affiliates (excluding Enterprise Products GP, Enterprise Products Partners and its subsidiaries, Enterprise GP Holdings L.P. and EPE Holdings, and TEPPCO, TEPPCO GP and their controlled affiliates). The ASA provides, among other things, that:

- if a business opportunity to acquire equity securities is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or us, then we will have the first right to pursue such opportunity. Equity securities are defined to include:

  - general partner interests (or securities which have characteristics similar to general partner interests) and incentive distribution rights or similar rights in publicly traded partnerships or interests in persons that own or control such general partner or similar interests (collectively, GP Interests) and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  - incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in persons that own or control such limited partner or similar interests (collectively, non-GP Interests); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

We will be presumed to desire to acquire the equity securities until such time as EPE Holdings advises the EPCO Group and Enterprise Products GP that we have abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the Audit and Conflicts Committee of EPE Holdings. If the purchase price is reasonably likely to be less than such threshold amount, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the Audit and Conflicts Committee of EPE Holdings. In the event that we abandon the acquisition and so notifies the EPCO Group and Enterprise Products GP, Enterprise Products Partners will have the second right to the pursue such acquisition. Enterprise Products Partners will be presumed to desire to acquire the equity securities until such time as Enterprise Products GP advises the EPCO Group that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to us, as

described above but utilizing Enterprise Products GP s Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the acquisition and so notifies the EPCO Group, the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

- if any business opportunity not covered by the preceding bullet point is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or us, Enterprise Products Partners will have the first right to pursue such opportunity. Enterprise Products Partners will be presumed to desire to pursue the business opportunity until such time as Enterprise Products GP advises the EPCO Group and EPE Holdings that Enterprise Products Partners has abandoned the pursuit of such business opportunity. In the event that the purchase price or cost associated with the business opportunity is reasonably likely to exceed $100 million, the decision to decline the business opportunity will be made by the Chief Executive Officer of Enterprise Products GP after consultation with and subject to the approval of the Audit and Conflicts Committee of Enterprise Products GP. If the purchase price or cost is reasonably likely to be less than such threshold amount, the Chief Executive Officer of Enterprise Products GP may make the determination to decline the business opportunity without consulting Enterprise Products GP s Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the business opportunity and so notifies the EPCO Group and EPE Holdings, we will have the second right to the pursue such business opportunity. We will be presumed to desire to pursue such business opportunity until such time as EPE Holdings advises the EPCO Group that we have abandoned the pursuit of such business opportunity. In determining whether or not to pursue the business opportunity, we will follow the same procedures applicable to Enterprise Products Partners, as described above but utilizing EPE Holdings Chief Executive Officer and Audit and Conflicts Committee. In the event that we abandon the business opportunity and so notifies the EPCO Group, the EPCO Group may pursue the business opportunity without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings, or us have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates, and TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or us.

The ASA also outlines an overall corporate governance structure and provides policies and procedures to address potential conflicts of interest among the parties to the ASA, including protection of the confidential information of each party from the other parties and the sharing of EPCO employees between the parties. Specifically, the ASA provides, among other things, that:

- there shall be no overlap in the independent directors of Enterprise Products GP, EPE Holdings and TEPPCO GP;

- there shall be no sharing of EPCO employees performing commercial and development activities involving certain defined potential overlapping assets between us, Enterprise Products Partners, and EPCO and its other affiliates (excluding TEPPCO and subsidiaries) on one hand and TEPPCO and its subsidiaries and TEPPCO GP on the other hand; and

- certain screening procedures are to be followed if an EPCO employee performing commercial and development activities becomes privy to commercial information relating to a potential overlapping asset of any entity for which such employee does not perform commercial and development activities.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 17 for a discussion of this alignment of commercial interests. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $318.8 million, $233.9 million and $212.7 million for 2005, 2004 and 2003. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Expenses with Promix were $26 million, $23.2 million and $17.5 million for 2005, 2004 and 2003. Additionally, revenues from Promix were $25.8 million, $18.6 million and $19.6 million for 2005, 2004 and 2003.

- We perform management services for certain of our unconsolidated affiliates. These fees were $8.3 million, $2.1 million and $1.5 million for 2005, 2004 and 2003.

Relationship with Shell

In 2004 and 2003, our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell. We also lease from Shell its 45.4% interest in one of our propylene fractionation facilities located in Mont Belvieu, Texas.

In connection with its March 2005 universal registration statement, Enterprise Products Partners registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units owned by a third party, Kayne Anderson MLP Investment Company, which had been acquired from Shell. Enterprise Products Partners was obligated to register the resale of these common units under a registration rights agreement it executed with Shell in connection with its September 1999 acquisition of certain assets of Shell's Gulf Coast midstream energy business.

19. Provision for Income Taxes for Certain Pipeline Operations

Our provision for income taxes relates to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represent our only consolidated subsidiaries subject to such income taxes. Our federal and state income tax provision is summarized below:

	For Year Ended December 31,		
	2005	**2004**	**2003**
Current:			
Federal	$ 1,105		
State	301	$ 157	$ 47
Total current	1,406	157	47
Deferred:			
Federal	5,968	1,620	4,556
State	988	1,984	690
Total deferred	6,956	3,604	5,246
Total provision for income taxes	$ 8,362	$ 3,761	$ 5,293

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes of these subsidiaries is as follows:

	For Year Ended December 31,		
	2005	**2004**	**2003**
Taxes computed by applying the federal statutory rate	$ 7,656	$ 2,308	$ 4,811
State income taxes (net of federal benefit)	838	1,392	479
Tax benefit charged to cumulative effect of change in accounting principle	65	0	0
Other permanent differences	(197)	61	3
Provision for income taxes	$ 8,362	$ 3,761	$ 5,293
Effective income tax rate	38%	57%	39%

The deferred tax asset shown on our consolidated balance sheet reflects the net tax effects of temporary differences between the subsidiary's carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The significant components of our deferred tax asset are as follows:

	At December 31,	
	2005	**2004**
Deferred Tax Assets:		
Property, plant and equipment Dixie	$ 855	
Net operating loss carryforwards	14,251	$ 11,735
Employee benefit plans	2,403	
Deferred revenue	448	520
Accruals	116	
Total Deferred Tax Assets	18,073	12,255
Deferred Tax Liabilities:		
Property, plant and equipment Seminole	13,907	5,269
Other	6	

Total Deferred Tax Liabilities	13,913	5,269
Net Deferred Tax Assets	$ 4,160	$ 6,986
Current portion of deferred tax assets	$ 554	$ 519
Long-term portion of deferred tax assets	$ 3,606	$ 6,467

20. Earnings per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing common units outstanding during a period. Enterprise GP Holdings L.P. currently has no dilutive securities. The amount of net income allocated to limited partner interests is derived by subtracting the general partner's share of the parent company s net income from net income. In connection with the August 2005 contribution of net assets to the parent company by affiliates of EPCO (see Note 1), such affiliates of EPCO received 74,667,332 of the parent company units as consideration.

The following table shows the allocation of net income to the parent company s general partner for the periods indicated:

	For The Year Ended December 31, 2005	2004	2003
Net income	$ 55,276	$ 29,778	$ 15,861
Multiplied by general partner ownership interest (1)	0.01%	0.01%	0.01%
Standard earnings allocation to Enterprise Products GP	$ 6	$ 3	$ 2

The following tables show the calculation of limited partners' interest in net income and basic and diluted earnings per unit.

	For The Year Ended December 31, 2005	2004	2003
Income before changes in accounting principles and general partner interest	$ 55,503	$ 29,562	$ 15,861
Cumulative effect of changes in accounting principles	(227)	216	
Net income	55,276	29,778	15,861
General partner interest in net income	(6)	(3)	(2)
Net income available to limited partners	$ 55,270	$ 29,775	$ 15,859
BASIC EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and general partner interest	$ 55,503	$ 29,562	$ 15,861
Cumulative effect of changes in accounting principles	(227)	216	
General partners' interest in net income	(6)	(3)	(2)
Limited partners' interest in net income	$ 55,270	$ 29,775	$ 15,859
Denominator			
Units	79,726	74,667	74,667
Basic earnings per unit			
Income before changes in accounting principles and general partner interest	$ 0.70	$ 0.40	$ 0.21
Cumulative effect of changes in accounting principles	*	*	
General partners' interest in net income	*	*	*
Limited partners' interest in net income	$ 0.69	$ 0.40	$ 0.21
DILUTED EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and general partner interest	$ 55,503	$ 29,562	$ 15,861
Cumulative effect of changes in accounting principles	(227)	216	
General partners' interest in net income	(6)	(3)	(2)
Limited partners' interest in net income	$ 55,270	$ 29,775	$ 15,859
Denominator			
Units	79,726	74,667	74,667
Diluted earnings per unit			
Income before changes in accounting principles and general partner interest	$ 0.70	$ 0.40	$ 0.21
Cumulative effect of changes in accounting principles	*	*	
General partners' interest in net income	*	*	*
Limited partners' interest in net income	$ 0.69	$ 0.40	$ 0.21

* Amount is negligible

21. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business operations, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activity. We are not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns the facility. It is possible, however, that MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits. In connection with our purchase of additional equity interests in the owner of the octane-additive production facility in 2003 from an affiliate of Devon Energy Corporation (Devon) and in 2004 from an affiliate of Sunoco, Inc. (Sun), Devon and Sun indemnified us for any liability (including liabilities described above) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in the facility.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2005. A description of each type of contractual obligation follows.

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**
Scheduled maturities of long-term debt	$ 5,000,567		$ 517,000		$ 634,500	$ 1,049,067	$ 2,800,000
Operating lease obligations	$ 179,623	$ 19,099	$ 18,638	$ 15,210	$ 10,352	$ 9,737	$ 106,587
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 1,518,016	$ 216,690	$ 216,690	$ 217,283	$ 216,690	$ 216,690	$ 433,973
NGLs	$ 6,095,907	$ 684,250	$ 619,048	$ 499,900	$ 499,900	$ 499,900	$ 3,292,909
Petrochemicals	$ 1,290,952	$ 1,079,110	$ 159,511	$ 52,331			
Other	$ 87,162	$ 31,578	$ 23,176	$ 21,548	$ 10,712	$ 148	
Underlying major volume commitments:							
Natural gas (in BBtus)	127,850	18,250	18,250	18,300	18,250	18,250	36,550
NGLs (in MBbls)	63,130	9,251	7,741	5,086	5,086	5,086	30,880
Petrochemicals (in MBbls)	19,717	16,525	2,381	811			
Service payment commitments	$ 5,765	$ 5,037	$ 689	$ 39			
Capital expenditure commitments	$ 208,575	$ 208,575					

Scheduled Maturities of Long-Term Debt. We have long and short-term payment obligations under debt agreements such as the indentures governing the Operating Partnership s senior notes and the credit agreements governing the Operating Partnership s Multi-Year Revolving Credit Facility and the parent company s credit facility. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. See Note 14 for additional information regarding our consolidated debt obligations. We have reclassified amounts due under the parent company s $525 Million Credit Facility to 2009 to reflect the parent company s refinancing of its long-term debt in January 2006. See Note 26 for information regarding this subsequent event.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year for the periods indicated.

Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 14 to 20 years and include renewal options that could extend the agreements for up to an additional 20 years. Our rental payments under these agreements are generally fixed rates, as specified in the individual contract, which may be subject to escalation provisions for inflation and other market-determined factors. With regards to our underground storage leases, we may also be assessed contingent rental payments when our storage volumes exceed our reserved capacity.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. In general, we are required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during 2005, 2004 or 2003.

The operating lease commitments shown in the preceding table exclude the non-cash related party expense associated with equipment leases contributed to us by EPCO at our formation (the retained leases). EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. EPCO s minimum future rental payments under these leases are $2.1 million for each of the years 2006 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us. During 2004, we exercised our option to purchase an isomerization unit and related equipment for $17.8 million. Should we decide to exercise the remaining purchase options, up to an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Lease and rental expense included in operating income was $34.9 million, $19.5 million and $17.8 million during 2005, 2004 and 2003, respectively.

Purchase Obligations. We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

We have long and short-term product purchase obligations for NGLs, petrochemicals and natural gas with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2005 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2005, we do not have any product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year.

We have long and short-term commitments to pay third-party providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

Lastly, we have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with the capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. Our capital expenditure commitments also include $95 million for the acquisition of certain pipeline assets during 2006. The preceding table shows these combined amounts for the periods indicated.

Redelivery Commitments

We transport and store NGL, petrochemical and natural gas volumes for third parties under various processing, storage, transportation and similar agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. We are insured for any physical loss of such volumes due to catastrophic events. At December 31, 2005, NGL and petrochemical volumes aggregating 15.2 million barrels were due to be redelivered to their owners along with 15,512 BBtus of natural gas.

Commitments under equity compensation plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 18). This includes the costs associated with equity-based awards granted to these employees. At December 31, 2005, there were 2,082,000 options outstanding to purchase common units of Enterprise Products Partners under the 1998 Plan that had been granted to employees for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of the unit option awards granted was $22.16 per common unit. At December 31, 2005, 727,000 of these unit options were exercisable. An additional 25,000, 840,000 and 490,000 of these unit options will be exercisable in 2006, 2008 and 2009, respectively. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 5 for additional information regarding our accounting for equity awards.

Performance Guaranty

In December 2004, a subsidiary of the Operating Partnership entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement, as amended, obligates the subsidiary (i) to construct an offshore platform production facility to process 1 Bcf/d of natural gas and condensate and (ii) to process certain natural gas and condensate production of the six producers following construction of the platform facility.

In conjunction with the Agreement, the Operating Partnership guaranteed the performance of its subsidiary under the Agreement up to $426 million. In December 2004, 20% of this guaranteed amount was assumed by Cal Dive, our joint venture partner in the Independence Hub project. The remaining $341 million represents our share of the anticipated cost of the platform facility. This amount represents the cap on the Operating Partnership's potential obligation to the six producers for the cost of constructing the platform in the remote scenario where the six producers take over the construction of the platform facility. This performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of the subsidiary shall have been terminated, paid or otherwise discharged in full, (ii) upon mutual written consent of our Operating Partnership and the producers or (iii) mechanical completion of the production facility. We expect that mechanical completion of the platform will occur in November 2006; therefore, we anticipate that the performance guaranty will exist until at least this future date.

In accordance with FIN 45, "*Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*," we recorded the fair value of the performance guaranty using an expected present value approach. Given the remote probability that our Operating Partnership would be required to perform under the guaranty, we have estimated the fair value of the performance guaranty at approximately $1.2 million, which is a component of other current liabilities on our Consolidated Balance Sheet at December 31, 2005.

22. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate predominantly in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

Credit Risk due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Counterparty Risk with respect to Financial Instruments

Where we are exposed to credit risk in our financial instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral and we do not anticipate nonperformance by our counterparties.

Weather-Related Risks

We participate as named insureds in EPCO s current insurance program, which provides us with property damage, business interruption and other coverages, which are customary for the nature and scope of our operations. Historically, most of the insurance carriers in EPCO s portfolio of coverage were rated A or higher by recognized ratings agencies. The financial impact of recent storm events such as Hurricanes Katrina and Rita has resulted in the lowering of credit ratings of many insurance carriers, with a number of providers also being placed on negative credit watch. We are unaware of any of our existing carriers dropping below the A rating level. At present, there is no indication of any insurance carrier in the EPCO insurance program being unable or unwilling to meet its coverage obligations.

We believe that EPCO maintains adequate insurance coverage on behalf of us, although insurance will not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available for only reduced amounts of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us or procure other desirable insurance on commercially reasonable terms, if at all. At present, the annualized cost of insurance premiums allocated to us by EPCO for all lines of coverage is approximately $21.1 million. This amount includes a $3.7 million increase in premiums related to Hurricanes Katrina and Rita that we recognized during 2005.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to partners and, accordingly, adversely affect the market price of our units.

The following is a discussion of the general status of insurance claims related to recent significant storm events that affected our assets. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur in the near term as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation for the GulfTerra Merger includes a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain GulfTerra assets caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004 prior to the GulfTerra Merger. These expenditures represent our total costs to restore the former GulfTerra damaged facilities to operation. Since this loss event occurred prior to completion of the GulfTerra Merger, the claim was filed under the insurance program of GulfTerra and El Paso. Since year end 2005, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million by mid-2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the fourth quarter of 2005, we received $4.8 million from such claims. In addition, we estimate an additional $15 million to $16 million will be received during the first quarter of 2006. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection and evaluation of property damage to our facilities is a continuing effort. We expensed $5 million during 2005 related to property damage insurance deductibles for these storms. To the extent that insurance proceeds from property damage claims do not cover our expenditures (in excess of the insurance deductibles we have expensed), such shortfall will be expensed when realized. We recorded $15.5 million of estimated recoveries from property damage claims based on amounts expended through December 31, 2005. In addition, we expect to file business interruption claims for losses related to these hurricanes. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

23. Supplemental Cash Flow Information

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for federal and state income taxes for the periods indicated.

	For Year Ended December 31, 2005	2004	2003
Decrease (increase) in:			
Accounts and notes receivable	$ (360,443)	$ (451,000)	$ (54,480)
Inventories	(148,846)	(44,202)	49,932
Prepaid and other current assets	(51,262)	2,726	11,073
Other assets	58,765	(6,073)	640
Increase (decrease) in:			
Accounts payable	47,609	108,458	(4,680)
Accrued gas payable	349,979	286,089	128,050
Accrued expenses	(161,989)	8,800	(16,677)
Accrued interest	(1,865)	2,617	15,012
Other current liabilities	2,651	6,268	(3,997)
Other liabilities	1,673	(4,137)	(610)
Net effect of changes in operating accounts	$ (263,728)	$ (90,454)	$ 124,263
Cash payments for interest, net of $22,046, $2,766 and $1,595 capitalized in 2005, 2004 and 2003, respectively	$ 259,304	$ 138,830	$ 112,712
Cash payments for federal and state income taxes	$ 5,160	$ 182	$ 453

Supplemental cash flow information regarding our investing activities related to business combinations and asset purchases in 2005, 2004 and 2003 are as follows:

	For Year Ended December 31, 2005	2004	2003
Fair value of assets acquired	$ 353,176	$ 5,946,291	$ 127,185
Less liabilities assumed	(23,940)	(4,810,662)	(70,037)
Net assets acquired	329,236	1,135,629	57,148
Less cash acquired	(2,634)	(40,968)	(19,800)
Cash used for business combinations, net of cash received	$ 326,602	$ 1,094,661	$ 37,348

We incurred liabilities for construction in progress and property additions that had not been paid at December 31, 2005, 2004 and 2003 of $130.2 million, $62.4 million and $9.1 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties may be obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $47 million, $8.9 million and $0.9 million as contributions in aid of our construction costs during 2005, 2004 and 2003, respectively.

Net income for 2005 includes a gain on the sale of assets of $5.5 million resulting from the sale of our 50% ownership interest in Starfish. We were required to sell our investment in Starfish in connection with gaining regulatory approval for the GulfTerra Merger.

Net income for 2004 includes a gain on sale of assets of $15.1 million resulting from the satisfaction of certain requirements of an asset sale agreement whereby we sold a 50% ownership interest in Cameron Highway to a third party. Of the $15.1 million gain we recognized, $5 million was realized in December 2004 and the remainder represents a receivable due from the third party in 2006.

In June 2005, we received $47.5 million in cash from Cameron Highway as a return of investment. These funds were distributed to us in connection with the refinancing of Cameron Highway s project debt (see Note 14).

In August 2005, various non-cash amounts were recorded by the parent company in connection with the contribution of net assets from affiliates of EPCO (see Note 1). In general, these contributions impacted investments, debt and partners' equity.

24. Selected Quarterly Data (Unaudited)

The following table presents selected quarterly financial data for 2005 and 2004:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2005: [1]				
Revenues	$ 2,555,522	$ 2,671,768	$ 3,249,291	$ 3,780,378
Operating income	165,004	125,334	193,995	176,755
Income before changes in accounting principles	9,535	10,767	15,301	19,900
Net income	9,535	10,767	15,301	19,673
Income per unit before changes in accounting principles:				
Basic and diluted	$ 0.13	$ 0.14	$ 0.19	$ 0.22
Net income per unit:				
Basic and diluted	$ 0.13	$ 0.14	$ 0.19	$ 0.22
For the Year Ended December 31, 2004: [1]				
Revenues	$ 1,704,890	$ 1,713,346	$ 2,040,271	$ 2,862,695
Operating income	88,752	65,826	92,693	175,118
Income before changes in accounting principles	11,066	6,730	3,660	8,106
Net income	11,282	6,730	3,660	8,106
Income per unit before changes in accounting principles:				
Basic and diluted	$ 0.15	$ 0.09	$ 0.05	$ 0.11
Net income per unit:				
Basic and diluted	$ 0.15	$ 0.09	$ 0.05	$ 0.11

(1) Our results of operations have increased since the completion of the GulfTerra Merger on September 30, 2004.

25. Condensed Financial Information of Operating Partnership

The Operating Partnership conducts substantially all of the business of Enterprise Products Partners. Currently, neither the parent company, Enterprise Products GP nor Enterprise Products Partners have any independent operations and any material assets outside those of the Operating Partnership.

Enterprise Products Partners acts as guarantor of all the Operating Partnership s consolidated debt obligations, with the exception of the Dixie revolving credit facility and the amounts remaining outstanding under GulfTerra s senior subordinated notes. If the Operating Partnership were to default on any debt Enterprise Products Partners guarantees, Enterprise Products Partners would be responsible for full repayment of that obligation. Enterprise Products Partners' guarantee of these debt obligations is both full and unconditional and non-recourse to Enterprise Products GP. For additional information regarding our consolidated debt obligations, see Note 14.

The reconciling items between our consolidated financial statements and those of the Operating Partnership are substantially the same as the differences between our consolidated financial statements and those of Enterprise Products Partners, as discussed in Note 1.

The following table shows condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

	December 31,	
	2005	2004
ASSETS		
Current assets	$ 1,960,015	$ 1,425,574
Property, plant and equipment, net	8,689,024	7,831,467
Investments in and advances to unconsolidated affiliates	471,921	519,164
Intangible assets, net	913,626	980,601
Goodwill	494,033	459,198
Deferred tax asset	3,606	6,467
Other assets	39,014	58,139
Total	$ 12,571,239	$ 11,280,610
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 1,894,227	$ 1,582,911
Long-term debt	4,833,781	4,266,236
Other long-term liabilities	84,486	63,521
Minority interest	106,159	73,858
Partners' equity	5,652,586	5,294,084
Total	$ 12,571,239	$ 11,280,610
Total Operating Partnership debt obligations guaranteed by Enterprise Products Partners	$ 4,844,000	$ 4,267,229

The following table shows condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

	For Year Ended December 31,		
	2005	2004	2003
Revenues	$ 12,256,959	$ 8,321,202	$ 5,346,431
Costs and expenses	11,605,923	7,946,816	5,083,701
Equity in income (loss) of unconsolidated affiliates	14,548	52,787	(13,960)
Operating income	665,584	427,173	248,770
Other income (expense)	(226,075)	(153,251)	(133,798)
Income before provision for income taxes, minority interest and changes in accounting principles	439,509	273,922	114,972
Provision for income taxes	(8,362)	(3,761)	(5,293)
Income before minority interest and changes in accounting principles	431,147	270,161	109,679
Minority interest	(5,989)	(8,072)	(3,095)
Income before changes in accounting principles	425,158	262,089	106,584
Cumulative effect of changes in accounting principles	(4,208)	10,781	
Net income	$ 420,950	$ 272,870	$ 106,584

26. Subsequent Events

January 2006 amendment to parent company credit facility

In January 2006, the parent company amended and restated its $525 Million Credit Facility to reflect a new borrowing capacity of $200 million, which includes a sublimit of $25 million for letters of credit. Amounts borrowed under the new $200 Million Credit Facility are due in January 2009. Borrowings under this credit agreement are secured by a pledge of (i) 13,454,498 common units of Enterprise Products Partners L.P and (ii) ownership interests in Enterprise Products GP that are owned by the parent company.

Amounts borrowed under this credit agreement will bear interest at a variable interest rate selected by the parent company at the time of each borrowing equal to (i) the greater of (a) the prime rate publicly announced by Citibank N.A. or (b) the Federal Funds Effective Rate plus 0.5% or (ii) a Eurodollar rate. Variable interest rates based on either the prime rate or Federal Funds Effective Rate will be increased by an applicable margin ranging from 0% to 0.75%. Variable interest rates based on Eurodollar rates will be increased by an applicable margin ranging from 1% to 1.75%.

The $200 Million Credit Facility contains various covenants related to the parent company s ability, and the ability of certain defined subsidiaries of the parent company (which defined subsidiaries exclude Enterprise Products GP and Enterprise Products Partners), to incur certain indebtedness, grant certain liens, make fundamental structural changes, make distributions following an event of default and enter into certain restricted agreements. The credit agreement also requires the parent company to satisfy certain quarterly financial covenants including (i) its leverage ratio must not exceed 4.5 to 1, except under certain circumstances and (ii) its minimum net worth must exceed $525 million.

SCHEDULE II

ENTERPRISE GP HOLDINGS L.P.

VALUATION AND QUALIFYING ACCOUNTS

Description	**Balance At Beginning Of Period**	**Additions Charged To Costs And Expenses**	**Charged To Other Accounts**	**Deductions**	**Balance At End of Period**
Accounts receivable trade					
Allowance for doubtful accounts (1)					
2005	$ 24,310	$ 2,238	$ 1,141	$ (1,840)	$ 25,849
2004	20,423	4,840	4,158	(5,111)	24,310
2003	21,196	1,239	71	(2,083)	20,423
Inventories					
Allowance for uncollectible imbalances (2)					
2005	8,463	3,153	4,400	(4,536)	11,480
2004			8,463		8,463
Other current liabilities					
Reserve for environmental liabilities (3)					
2005	115	95	65		275
2004	9		115	(9)	115
2003	9				9
Reserve for inventory gains and losses (4)					
2005	750	4,761	8,314	(3,825)	10,000
2004	2,700	900		(2,850)	750
2003	1,271	3,000		(1,571)	2,700
Reserve for BEF turnaround accrual (5)					
2004	2,013			(2,013)	-
2003			2,124	(111)	2,013
Other long-term liabilities					
Reserve for environmental liabilities (3)					
2005	22,004	44	(65)	(168)	21,815
2004	1,133		21,136	(265)	22,004
2003	135		1,061	(63)	1,133
Reserve for BEF turnaround accrual(5)					
2004	5,001			(5,001)	-
2003			5,001		5,001

(1) Additions charged to costs and expenses primarily represent periodic accruals for uncollectible accounts based on specific identification and estimates of future uncollectible accounts. Additions charged to other accounts primarily represent net realizable values recorded in connection with business combinations. Deductions primarily represent uncollectible accounts receivable charged to the reserve. See Note 2 for additional information regarding our allowance for doubtful accounts.

(2) Additions charged to costs and expenses primarily represent periodic accruals for uncollectible natural gas imbalance receivable based on specific identification of problem accounts. Additions charged to other accounts primarily represent uncollectible natural gas imbalance receivables charged to the reserve. See Note 2 for additional information regarding our natural gas imbalances.

(3) Additions charged to costs and expenses primarily represent periodic accruals for environmental remediation costs. Additions charged to other accounts primarily represent present values recorded in connection with business combinations. Deductions primarily represent environmental remediation costs charged to the reserve. See Note 2 for additional information regarding our environmental costs.

(4) This reserve exists to cover anticipated net losses attributable to the storage of NGL and petrochemical products in underground storage caverns. Additions charged to costs and expense primarily represent periodic accruals for net well losses. Additions charged to other accounts primarily represent product gains. Deductions primarily represent product losses. Management regularly reviews the status of the reserve and determines the appropriate level based on historical and anticipated storage well activity. The reserve increased during 2005 generally due to expected storage well activity and the acquisition of storage assets during the period.

(5) We eliminated this reserve in connection with changing the accounting principle used by a subsidiary related to its planned major maintenance activities. See Note 8 for additional information regarding this change in accounting principle.

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

None.

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

Disclosure controls and procedures

Our management, with the participation of the CEO and CFO of our general partner, has evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2005. Our management concluded that our disclosure controls and procedures, including internal controls over financial reporting, are effective to ensure that material information relating to our partnership is made known to management on a timely basis. Our management noted no material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. In addition, no fraud involving management or employees who have a significant role in our internal controls over financial reporting was detected.

Our disclosure controls and procedures are designed to provide us with a reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO of our general partner, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. 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. Based on 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 errors or mistakes. 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 controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events. Therefore, 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. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of December 31, 2005, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Internal control over financial reporting

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements in accordance with GAAP. These internal controls over financial reporting were designed under the supervision of our management, including the CEO and CFO of our general partner, and include policies and procedures that: (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

In accordance with SEC Regulations regarding the reporting of Internal Controls over Financial Reporting, our management is not required to provide an annual report regarding internal controls over our financial reporting because we are not considered an accelerated filer because we have not completed 12 calendar months of operations. The report for the year ended December 31, 2006 will include management's assessment of the effectiveness of our internal controls over financial reporting.

Changes in internal control over financial reporting during the fourth quarter of 2005. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act), or in other factors that occurred during the fiscal quarter ended December 31, 2005, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

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

None.

PART III

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

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to an administrative services agreement under the direction of the Board of Directors and executive officers of EPE Holdings, our general partner. For a description of the administrative services agreement, please read *Certain Relationships and Related Transactions Relationship with EPCO and its other affiliates* under Item 13 of this annual report.

Directors and Executive Officers of EPE Holdings

The following table sets forth the name, age and position of each of the directors and executive officers of EPE Holdings at February 27, 2006. Each member of the Board of Directors of EPE Holdings serves until such member s death, resignation or removal. The executive officers of EPE Holdings are elected for one-year terms and may be removed, with or without cause, only by the Board of Directors. Our unitholders do not elect the officers or directors of EPE Holdings. Dan. L. Duncan, through his indirect control of EPE Holdings, has the ability to elect, remove and replace at any time, all of the officers and directors of EPE Holdings.

Notwithstanding any contractual limitation on its obligations or duties, EPE Holdings is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to EPE Holdings. Whenever possible, EPE Holdings intends to make any such indebtedness or other obligations non-recourse to itself.

Name	**Age**	**Position with EPE Holdings**
Dan L. Duncan (1)	73	Director and Chairman
Michael A. Creel (1)	52	Director, President and Chief Executive Officer
Richard H. Bachmann (1)	53	Director, Executive Vice President, Chief Legal Officer and Secretary
W. Randall Fowler (1)	49	Director, Senior Vice President and Chief Financial Officer
Robert G. Phillips	51	Director
W. Matt Ralls (2,3,4)	56	Director
Charles E. McMahen (2,3,5)	66	Director
Edwin E. Smith (2,3)	74	Director
Michael J. Knesek (1)	51	Senior Vice President, Controller and Principal Accounting Officer

(1) Executive officer

(2) Member of Audit and Conflicts Committee

(3) Member of Governance Committee

(4) Chairman of the Audit and Conflicts Committee

(5) Chairman of the Governance Committee

Because we are a limited partnership and meet the definition of a controlled company under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Directors of EPE Holdings be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Directors of EPE Holdings maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Dan L. Duncan was elected Chairman and a Director of EPE Holdings in August 2005, Chairman and a Director of Enterprise Products GP in April 1998 and Chairman and a Director of the general partner of the Operating Partnership in December 2003. Mr. Duncan has served as Chairman of EPCO since 1979.

Michael A. Creel was elected President, Chief Executive Officer and a Director of EPE Holdings in August 2005 and a Director of Enterprise Products GP and the general partner of TEPPCO (referred to as TEPPCO GP) in February 2006. Mr. Creel was elected Executive Vice President of Enterprise Products GP and EPCO in January 2001, after serving as a Senior Vice President of Enterprise Products GP and EPCO from November 1999 to January 2001. Mr. Creel, a certified public accountant, served as Chief Financial Officer of EPCO from June 2000 through April 2005 and was named Chief Operating Officer of EPCO in April 2005. In June 2000, Mr. Creel was also named Chief Financial Officer of Enterprise Products GP. Mr. Creel has served as a Director of the general partner of the Operating Partnership since December 2003 and was elected a Director of Edge Petroleum Corporation (a publicly traded oil and natural gas exploration and production company) in October 2005.

Richard H. Bachmann was elected Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings in August 2005 and a Director of EPE Holdings, Enterprise Products GP and TEPPCO GP in February 2006. Mr. Bachmann previously served as a Director of Enterprise Products GP from June 2000 to January 2004. Mr. Bachmann was elected Executive Vice President, Chief Legal Officer and Secretary of Enterprise Products GP and EPCO in January 1999. Mr. Bachmann has served as a Director of the general partner of the Operating Partnership since December 2003.

W. Randall Fowler was elected Senior Vice President and Chief Financial Officer of EPE Holdings in August 2005 and a Director of EPE Holdings, Enterprise Products GP and TEPPCO GP in February 2006. Mr. Fowler was named Senior Vice President and Treasurer of Enterprise Products GP in February 2005 and Chief Financial Officer of EPCO in April 2005. Mr. Fowler, a certified public accountant (inactive), joined us as Director of Investor Relations in January 1999 and served as Treasurer and a Vice President of Enterprise Products GP and EPCO from August 2000 to February 2005.

Robert G. Phillips was elected a Director of EPE Holdings in February 2006 and President and Chief Executive Officer of Enterprise Products GP in February 2005. Mr. Phillips served as President and Chief Operating Officer of Enterprise Products GP from September 2004 to February 2005. Mr. Phillips has served as a Director of Enterprise Products GP since September 2004 and as a Director of the general partner of the Operating Partnership since September 2004. Mr. Phillips served as a Director of GulfTerra's general partner from August 1998 until September 2004. He served as Chief Executive Officer for GulfTerra and its general partner from November 1999 until September 2004 and as Chairman from October 2002 until September 2004. He served as Executive Vice President of GulfTerra from August 1998 to October 1999. Mr. Phillips served as President of El Paso Field Services Company from June 1997 to September 2004. He served as President of El Paso Energy Resources Company from December 1996 to July 1997, President of El Paso Field Services Company from April 1996 to December 1996 and Senior Vice President of El Paso Corporation from September 1995 to April 1996. For more than five years prior, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

W. Matt Ralls was elected a Director of EPE Holdings in February 2006 after serving as a Director of Enterprise Products GP from September 2004 to February 2006. Mr. Ralls also served as a Director of GulfTerra s general partner from May 2003 to September 2004. Mr. Ralls served as Senior Vice President and Chief Financial Officer of GlobalSantaFe Corporation (GlobalSantaFe), an international contract drilling company, from 2001 to June 2005 and was elected Executive Vice President and Chief Operating Officer of GlobalSantaFe in June 2005. From 1997 to 2001, he was Vice President, Chief Financial Officer and Treasurer of Global Marine, Inc. Previously, he served as Executive Vice President, Chief Financial Officer and director of Kelly Oil and Gas Corporation and as Vice President of Capitals Markets and Corporate Development for the Meridian Resource Corporation before joining Global Marine. He spent the first seventeen years of his career in commercial banking at the senior management level. Mr. Ralls serves as Chairman of EPE Holdings Audit and Conflicts Committee and a member of its Governance Committee.

Charles E. McMahen was elected a Director of EPE Holdings in August 2005. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and Chief Executive Officer of Compass Banks of Texas from March 1990 until

March 1999. Mr. McMahen was named to the Board of Directors of Compass Bancshares, Inc. in 2001 and remains a director of Compass Bancshares, Inc. Mr. McMahen also serves as a Director, Chairman of the Audit and Ethics Committee and a member of the Human Resources and Compensation Committee of PNM Resources, Inc., a publicly traded energy holdings company. Mr. McMahen served on the Board of Directors and Executive Committee of the Greater Houston Partnership from 1995 to 2003. He also served as Chairman of the Board of Regents of the University of Houston from September 1998 to August 2000. Mr. McMahen serves as Chairman of EPE Holdings Governance Committee and as a member of its Audit and Conflicts Committee.

Edwin E. Smith was elected a Director of EPE Holdings in August 2005. Mr. Smith has been a private investor since he retired from Allied Bank of Texas in 1989 after a 31-year career in banking. Mr. Smith serves as a director of Encore Bank and previously served as a director of EPCO from 1987 until 1997. Mr. Smith serves as a member of EPE Holdings Audit and Conflicts Committee and Governance Committee.

Michael J. Knesek, a certified public accountant, was elected Senior Vice President and Principal Accounting Officer of EPE Holdings in August 2005 and of Enterprise Products GP in February 2005. Previously, Mr. Knesek served as Principal Accounting Officer and a Vice President of Enterprise Products GP from August 2000 to February 2005. Mr. Knesek has been the Controller and a Vice President of EPCO since 1990.

Directors and Executive Officers of Enterprise Products GP

The following table sets forth the name, age and position of each of the directors and executive officers of our wholly owned subsidiary, Enterprise Products GP, at February 27, 2006. Each member of the Board of Directors of Enterprise Products GP serves until such member s death, resignation or removal. The executive officers of Enterprise Products GP are elected for one-year terms and may be removed, with or without cause, only by the Board of Directors of Enterprise Products GP. Enterprise Products Partners unitholders do not elect the officers or directors of Enterprise Products GP. Dan. L. Duncan, through his indirect control of Enterprise Products GP, has the ability to elect, remove and replace at any time, all of the officers and directors of Enterprise Products GP.

Name	Age	Position with Enterprise Products GP
Dan L. Duncan (1)	73	Director and Chairman
Robert G. Phillips (1)	51	Director, President and Chief Executive Officer
Dr. Ralph S. Cunningham (1)	65	Director, Group Executive Vice President and Chief Operating Officer
Michael A. Creel (1)	52	Director, Executive Vice President and Chief Financial Officer
Richard H. Bachmann (1)	53	Director, Executive Vice President, Chief Legal Officer and Secretary
W. Randall Fowler (1)	49	Director, Senior Vice President and Treasurer
E. William Barnett (2,3,5)	73	Director
Philip C. Jackson (2,3,4)	77	Director
Stephen L. Baum (2,3)	65	Director
James H. Lytal (1)	48	Executive Vice President
A.J. Teague (1)	60	Executive Vice President
Michael J. Knesek (1)	51	Senior Vice President, Controller and Principal Accounting Officer

(1) Executive officer

(2) Member of Audit and Conflicts Committee

(3) Member of Governance Committee

(4) Chairman of Audit and Conflicts Committee

(5) Chairman of Governance Committee

To the extent we have described the business experience of these individuals in the previous section titled *Directors and Executive Officers of EPE Holdings*, we have not repeated that information here.

Dr. Ralph S. Cunningham was elected Group Executive Vice President and Chief Operating Officer of Enterprise Products GP in December 2005 and a Director in February 2006. Dr. Cunningham previously served as a Director of Enterprise Products GP from 1998 until March 2005 and served as Chairman and a Director of TEPPCO GP from March 2005 until November 2005. He retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), EnCana Corporation (a Canadian publicly traded independent oil and natural gas company) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company) and was a Director of EPCO from 1987 to 1997.

E. William Barnett was elected a Director of Enterprise Products GP in March 2005. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for fourteen years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005. He is a Life Trustee of The University of Texas Law School Foundation; a Director of St. Luke's Episcopal Health System; a Director of the Center for Houston s Future and a current Director and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo). He is a Director of Reliant Energy, Inc., a publicly traded electric services company. He is also Director and former Chairman of the Greater Houston Partnership and Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University. He also served as a trustee of Baylor College of Medicine from 1993 until 2004. Mr. Barnett is a member of Enterprise Products GP s Audit and Conflicts Committee and serves as Chairman of its Governance Committee.

Philip C. Jackson was elected a Director of Enterprise Products GP in August 2005. Mr. Jackson was an Adjunct Professor of Finance at Birmingham-Southern College from 1989 until his retirement in 1999. Mr. Jackson served as Vice Chairman of Compass Bancshares, Inc. from 1980 until 1989 and as a consultant and outside Director from 1978 until 1980. He was a member of the Board of Governors of the Federal Reserve System from 1975 until 1978. Mr. Jackson is a member of the Advisory Board of Compass Bank; a Trustee of Birmingham-Southern College; a Director of Saul Centers, Inc., a publicly traded real estate investment trust; and a Governor of the Mortgage Bankers Association of America. Mr. Jackson is a member of Enterprise Products GP s Governance Committee and serves as Chairman of its Audit and Conflicts Committee.

Stephen L. Baum was elected a Director of Enterprise Products GP in February 2006. Mr. Baum served as Chairman, Chief Executive Officer and a Director of Sempra Energy from September 2000 until his retirement in January 2006. He served as Vice Chairman and Chief Operating Officer of Sempra Energy from June 1998 to June 2000. Mr. Baum was President and Chief Executive Officer of Enova Corp., the parent company of San Diego Gas & Electric (SDG&E) from 1996 to 1997, and was an Executive Vice President of SDG&E from 1993 to 1996. Prior to joining SDG&E in 1985, he was Senior Vice President and General Counsel of the New York Power Authority from 1982 to 1985. Mr. Baum has served as a Director of Computer Sciences Corp. (a publicly traded information technology company) since 1999 and serves as Chairman of its Audit Committee. Mr. Baum serves on the Audit and Conflicts Committee and the Governance Committee of Enterprise Products GP.

James H. Lytal was elected Executive Vice President of Enterprise Products GP in September 2004. Mr. Lytal served as a Director of GulfTerra s general partner from August 1994 until September 2004, and as President of GulfTerra and its general partner from July 1995 until September 2004. He served as Senior Vice President of GulfTerra and its general partner from August 1994 to June 1995. Prior to joining GulfTerra, Mr. Lytal served in various capacities with the oil and gas exploration and production and natural gas pipeline businesses of United Gas Pipeline Company, Texas Oil and Gas, Inc. and American Pipeline Company.

A.J. Teague was elected an Executive Vice President of Enterprise Products GP in November 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC.

Governance Matters of EPE Holdings

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders. The following is a brief description of certain existing practices we use to maintain strong governance principles.

Independence of Board Members. A key element for strong governance is independent members of the board of directors. Pursuant to the NYSE listing standards, a director will be considered independent if the board determines that he or she does not have a material relationship with EPE Holdings or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise Products GP or us). Based on the foregoing, the Board has affirmatively determined that W. Matt Ralls, Charles E. McMahen and Edwin E. Smith are independent directors under the NYSE rules.

Heightened Independence for Audit and Conflicts Committee Members. As required by the Sarbanes-Oxley Act of 2002, the SEC adopted rules that direct national securities exchanges and associations to prohibit the listing of securities of a public company if members of its audit committee do not satisfy a heightened independence standard. In order to meet this standard, a member of an audit committee may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member and may not be considered an affiliate of the public company. Neither EPE Holdings nor any individual member of its Audit and Conflicts Committee has relied on any exemption in the NYSE rules to establish such individual's independence. Based on the foregoing criteria, the Board of Directors of EPE Holdings has affirmatively determined that all members of its Audit and Conflicts Committee satisfy this heightened independence requirement.

Audit Committee Financial Expert. An audit committee plays an important role in promoting effective corporate governance, and it is imperative that members of an audit committee have requisite financial literacy and expertise. As required by the Sarbanes-Oxley Act of 2002, SEC rules require that a public company disclose whether or not its audit committee has an audit committee financial expert as a member. An audit committee financial expert is defined as a person who, based on his or her experience, satisfies all of the following attributes:

- An understanding of generally accepted accounting principles and financial statements.
- An ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves.
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more persons engaged in such activities.
- An understanding of internal controls and procedures for financial reporting.
- An understanding of audit committee functions.

Based on the information presented, the Board of Directors has affirmatively determined that W. Matt Ralls satisfies the definition of audit committee financial expert.

Executive Sessions of Board. The Board of Directors of EPE Holdings holds regular executive sessions in which non-management board members meet without any members of management present.

The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the Presiding Director, who is responsible for leading and facilitating such executive sessions. Currently, the Presiding Director is W. Matt Ralls, the Chairman of the Audit and Conflicts Committee.

In accordance with the rules of the NYSE, we have designated our toll-free, confidential Hotline as the method for interested parties to communicate with the Presiding Director, alone, or with the non-management Directors of Enterprise Products GP as a group. All calls to this Hotline are reported to the Chairman of the Audit and Conflicts Committee of Enterprise Products GP, who is responsible for communicating any necessary information to the other non-management directors as a group. The number of our confidential Hotline is (877) 888-0002. The Hotline is operated by The Network, an independent contractor that specializes in providing feedback/reporting services to more than 1,000 companies in a variety of industries

Committees of Board of Directors. The Board of Directors of EPE Holdings has two committees, the Audit and Conflicts Committee and the Governance Committee, which are described in the following sections:

Audit and Conflicts Committee of EPE Holdings

In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board of Directors of EPE Holdings has named three of its members to serve on its Audit and Conflicts Committee. The members of the Audit and Conflicts Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

The members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the committee shall have accounting or related financial management expertise. The members of the Audit and Conflicts Committee are Charles E. McMahen, Edwin E. Smith and W. Matt Ralls, Chairman. The primary responsibilities of the Audit and Conflicts Committee include:

- monitoring the integrity of our financial reporting process and related systems of internal control;
- ensuring our legal and regulatory compliance and that of EPE Holdings;
- overseeing the independence and performance of our independent public accountants;
- approving all services performed by our independent public accountants;
- providing for an avenue of communication among the independent public accountants, management, internal audit function and the Board of Directors;
- encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;

- reviewing areas of potential significant financial risk to our businesses; and

- approving awards granted under our 2005 EPE Long-Term Incentive Plan.

The Audit and Conflicts Committee also has the authority to review specific matters as to which the Board of Directors believes there may be a conflict of interests in order to determine if the resolution of such conflict proposed by EPE Holdings is fair and reasonable to us. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by EPE Holdings or its Board of Directors of any duties they may owe us or our unitholders.

Pursuant to its formal written charter adopted in August 2005, the Audit and Conflicts Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee of EPE Holdings

The Governance Committee of EPE Holdings Board of Directors is comprised of the three independent directors (W. Matt Ralls, Edwin E. Smith and Charles E. McMahen, Chairman). The Governance Committee is appointed by the Board to assist the Board in fulfilling its oversight responsibilities. The Governance Committee s primary duties and responsibilities are to develop and recommend to the Board a set of governance principles applicable to us, review the qualifications of candidates for Board membership, screen and interview possible candidates for Board membership and communicate with members of the Board regarding Board meeting format and procedures.

Governance Guidelines. Governance guidelines, together with committee charters, provide the framework for effective governance. The Board of Directors of EPE Holdings has adopted the Governance Guidelines of Enterprise GP Holdings, which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of committees, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board of Directors of EPE Holdings recognizes that effective governance is an on-going process, and thus, the Board will review the Governance Guidelines of Enterprise GP Holdings annually or more often as deemed necessary.

Code of Conduct. EPE Holdings has adopted a Code of Conduct that applies to all directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code.

Code of Ethics. EPE Holdings has adopted a code of ethics, the Code of Ethical Conduct for Senior Financial Officers and Managers, that applies to our CEO, CFO, Principal Accounting Officer and senior financial and other managers. In addition to other matters, this code of ethics establishes policies to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting violations of the code.

Web Access. We provide access through our website at www.enterprisegp.com to current information relating to governance, including the Audit and Conflicts Committee Charter, the Governance Committee Charter, the Code of Ethical Conduct for Senior Financial Officers and Managers, the Governance Guidelines of Enterprise GP Holdings and other matters impacting our governance principles. You may also contact our investor relations department at (713) 426-4500 for printed copies of these documents free of charge.

Indemnification of Directors and Officers. Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events any person who is or was an employee (other than an officer) or agent of our partnership.

Section 16(a) Beneficial Ownership Reporting Compliance of EPE Holdings

Under the federal securities laws, EPE Holdings, directors of EPE Holdings, executives (and certain other) officers, and any persons holding more than 10% of our units are required to report their ownership of units and any changes in that ownership to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this report any failure to file by these dates during 2005. We filed a late report during 2005 on behalf of Edwin E. Smith covering one transaction completed in 2005.

Item 11. ***Executive Compensation.***

We are managed by our general partner, Enterprise Products GP, the executive officers of which are employees of EPCO. Our reimbursement for the compensation of executive officers is governed by the administrative services agreement with EPCO (see Item 13 of this annual report).

Summary Compensation Table

The following table presents cash compensation paid or awarded by us in 2005 with respect to our Chief Executive Officer and our four other most highly compensated executive officers at December 31, 2005 (collectively, the named executive officers). Our named executive officers include those of our wholly-owned subsidiary, Enterprise Products GP, which is the managing partner of Enterprise Products Partners. The executive officers of Enterprise Products GP routinely perform policy-making functions that determine the success of our business strategy. Apart from the compensation paid or accrued by Enterprise Products GP, the executive officers of Enterprise Products GP receive no additional compensation from EPE Holdings or us for the services these individuals perform on our behalf.

The amounts presented for each named executive officer s annual salary, bonus and all other compensation represent consolidated compensation expense recognized by us that was earned by such individual during the year noted.

All of our named executive officers are employees of EPCO and are participants in its long-term incentive arrangements. The named executive officers have been granted by EPCO nonvested (or restricted) unit awards of Enterprise Products Partners and options to acquire common units of Enterprise Products Partners.

				Long-term Compensation Awards		
				Restricted	Securities	
Name and		Annual Compensation		Unit	Underlying	All Other
Principal Position	Year	Salary	Bonus	Awards ($)(1)	Options (#)	Compensation(2)
Robert G. Phillips, (3,4)	2005	$675,000	$200,000	$529,400	70,000	$14,700
Chief Executive Officer	2004	150,000		991,910	500,000	10,500
of Enterprise Products GP						
O.S. Andras, (5)	2005	402,600				11,550
Former Chief Executive	2004	798,000				14,350
Officer of Enterprise	2003	877,800				14,000
Products GP						
A. J. Teague, (6)	2005	412,000	90,000	264,700	35,000	14,700
Executive Vice President	2004	392,500	50,000	251,400	35,000	14,350
of Enterprise Products GP	2003	381,280	80,000			14,000
James H. Lytal, (3,7)	2005	338,750	100,000	264,700	35,000	4,200
Executive Vice President	2004	80,000		873,311	35,000	1,600
of Enterprise Products GP						
Michael A. Creel, (8)	2005	166,813	51,000	264,700	35,000	6,248
Chief Executive Officer						
of EPE Holdings						

(1) The dollar value of time-vested restricted common unit awards is calculated by multiplying the number of units awarded by the closing price of Enterprise Products Partners unrestricted common units on the date of each grant. Time-vested restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on time-vested restricted common units lapse four years from the date of grant. During the vesting period, each holder of time-vested restricted units is entitled to receive cash distributions per unit in an amount equal to those received by Enterprise Products Partners common unitholders.

(2) These amounts primarily represent contributions made by EPCO to the 401(k) plan of the named executive officers.

(3) Mr. Phillips and Mr. Lytal became executive officers of Enterprise Products GP in September 2004 upon completion of the GulfTerra Merger. Mr. Phillips became the Chief Executive Officer of Enterprise Products GP in February 2005.

(4) At December 31, 2005, Mr. Phillips held 62,553 time-vested restricted units valued at $1,501,898 based on a closing price of $24.01 per unit for Enterprise Products Partners unrestricted common units on that date. Mr. Phillips became the Chief Executive Officer of Enterprise Products GP in February 2005.

(5) Mr. Andras resigned his position as Chief Executive Officer of Enterprise Products GP in February 2005; however, he remained a non-executive officer of Enterprise Products GP until his retirement in June 2005.

(6) At December 31, 2005, Mr. Teague held 22,000 time-vested restricted units valued at $528,220 based on a closing price of $24.01 per unit for Enterprise Products Partners unrestricted common units on that date.

(7) At December 31, 2005, Mr. Lytal held 47,532 time-vested restricted units valued at $1,141,243 based on a closing price of $24.01 per unit for Enterprise Products Partners unrestricted common units on that date.

(8) Mr. Creel became Chief Executive Officer of EPE Holdings in 2005. At December 31, 2005, Mr. Creel held 64,553 time-vested restricted units valued at $1,549,918 based on a closing price of $24.01 per unit for Enterprise Products Partners unrestricted common units on that date. The salary and bonus amounts presented for Mr. Creel represent the value of his services provided to us.

Unit Option Grants to Named Executive Officers during 2005

We have not granted any unit options to our executive officers. The following table provides information concerning the award of options to purchase common units of Enterprise Products Partners to the named executive officers during 2005. These awards were made under EPCO s 1998 Long-Term Incentive Plan (the 1998 Plan).

Name	Number of Securities Underlying Options Granted (#)	Individual Grants Percent of Total Options Granted to EPCO Employees in 2005	Exercise Price ($/Unit)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Unit Price Appreciation for Option Term [(1)] 5% ($)	10% ($)
Robert G. Phillips	70,000	13.2%	$ 26.47	Aug. 2009	$ 399,000	$ 859,600
A.J. Teague	35,000	6.6%	$ 26.47	Aug. 2009	199,500	429,800
James H. Lytal	35,000	6.6%	$ 26.47	Aug. 2009	199,500	429,800
Michael A. Creel	35,000	6.6%	$ 26.47	Aug. 2009	199,500	429,800

(1) These amounts represent the result of calculations at the 5% and 10% assumed compounded appreciation rates from the date of grant to the end of the option term (i.e., the expiration date) as required by the SEC by Item 402(c)(2)(vi)(A) of Regulation S-K and are not intended to forecast the future trading prices of Enterprise Products Partners common units.

Common Unit Options Exercised by Named Executive Officers and Fiscal Year-End Values

The following table provides information concerning (i) the exercise of options to purchase common units of Enterprise Products Partners by the named executive officers during 2005 and (ii) the value of unexercised options to purchase common units of Enterprise Products Partners held by such individuals at December 31, 2005.

Name	Units Acquired on Exercise (#)	Value Realized ($) [(1)]	Number of Securities Underlying Unexercised Options at December 31, 2005 Exercisable	Unexercisable	Value of Unexercised In-the-Money Options at December 31, 2005 [(2)] Exercisable	Unexercisable
Robert G. Phillips				570,000		$ 415,000
A.J. Teague	100,000	$ 1,000,750		70,000		140,350
James H. Lytal				70,000		29,050
Michael A. Creel	150,000	1,748,500		70,000		140,350

(1) The "value realized" represents the difference between the exercise price of the common unit options and the market (sale) price of the common units on the date of exercise without considering any taxes that may have been owed by the beneficiary.

(2) Value is based on the $24.01 closing price of Enterprise Products Partners common units on December 31, 2005.

Equity Awards Under EPE Unit L.P.

All of the named executive officers are Class B limited partners of EPE Unit L.P. (the Employee Partnership). For information regarding the Employee Partnership, please read *Relationship with EPCO and affiliates* included under Item 13 of this annual report.

At December 31, 2005, the named executive officers approximate percentage interest in the total profits interest of the Employee Partnership were as follows: Robert G. Phillips, 6.9%; Michael A. Creel, 6.9%; A. J. Teague, 4.6%; and James H. Lytal, 4.6%. If the Employee Partnership had been liquidated at December 31, 2005, the estimated value of the total profits interest would have been approximately $16.8 million, of which each named executive officer would have received his proportionate share.

Compensation of Directors of EPE Holdings

Neither we nor EPE Holdings provide any additional compensation to employees of EPCO who serve as directors of our general partner. The employees of EPCO who served as directors of EPE Holdings during 2005 were Mr. Duncan and Mr. Creel. The employees of EPCO currently serving as directors are Messrs. Duncan, Creel, Phillips, Bachmann and Fowler.

At February 27, 2006, our independent directors are Messrs. McMahen, Smith and Ralls. EPE Holdings is responsible for compensating these directors for their services. Its standard compensation arrangement is as follows:

- Each independent director receives $50,000 in cash annually.
- If the individual serves as chairman of a committee of the Board of Directors, then he receives an additional $7,500 in cash annually.

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

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information as of February 15, 2006, regarding the beneficial ownership of our units by:

- each person known by EPE Holdings to beneficially own more than 5% of our units;
- each of the named executive officers at December 31, 2005 of EPE Holdings;
- all of the current directors of EPE Holdings; and
- all of the current directors and executive officers of EPE Holdings as a group.

The table also presents the ownership of common units of Enterprise Products Partners by the directors and executive officers of EPE Holdings. We are the sole member of Enterprise Products GP, which is the managing partner of Enterprise Products Partners.

All information with respect to beneficial ownership has been furnished by the respective directors or officers, as the case may be. Each person has sole voting and dispositive power over the units shown unless otherwise indicated below. The beneficial ownership amounts of certain individuals include options to acquire common units of Enterprise Products Partners that are exercisable within 60 days of the filing date of this annual report (see footnotes).

Security Ownership of Certain Beneficial Owners and Management

	Limited Partner Ownership Interests In			
	Enterprise GP Holdings		Enterprise Products Partners	
Name of Beneficial Owner	**Amount And Nature Of Beneficial Ownership**	**Percent of Class**	**Amount And Nature Of Beneficial Ownership**	**Percent of Class**
Dan Duncan:				
Units owned by EPCO: [1,2]				
DFI Delaware Holdings L.P.			118,078,425	30.3%
Duncan Family Interests, Inc.	71,119,631	80.0%		
Enterprise GP Holdings L.P.			13,454,498	3.4%
Units owned by Dan Duncan LLC [3]	3,726,273	4.2%		
Units owned by Employee Partnership [4]	1,821,428	2.0%		
Units owned by trusts [5]	233,271	*	11,925,670	3.1%
Units owned directly			695,400	*
Total for Dan L. Duncan	76,900,603	86.5%	144,153,993	36.9%
Michael A. Creel	35,000	*	102,828	*
Richard H. Bachmann	20,000	*	101,984	*
W. Randall Fowler	3,000	*	48,061	*
W. Matt Ralls			5,099	*
Edwin E. Smith	13,800	*	95,167	*
Charles E. McMahen	10,000	*		
Robert G. Phillips [6,7]	75,000	*	105,343	*
O.S. Andras [6,8]	185,000	*	3,676,525	*
All current directors and executive officers of EPE Holdings, 11 individuals in total [9]	77,278,403	86.9%	148,558,258	38.1%

** The beneficial ownership of each individual is less than 1% of the registrant s units outstanding.*

(1) Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the units beneficially owned by EPCO. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of the members of Mr. Duncan s family. The address of EPCO is 2707 North Loop West, Houston, Texas 77008 and the address of Mr. Duncan is 2727 North Loop West, Houston, Texas 77008.

(2) Essentially all of the ownership interests in Enterprise Products Partners and Enterprise GP Holdings L.P. that are owned or controlled by EPCO are pledged as security under an EPCO affiliate s credit facility. EPCO s credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise Products Partners, us and TEPPCO. In the event of a default under this credit facility, a change in control of Enterprise GP Holdings L.P. or Enterprise Products Partners could occur. A change in control of Enterprise GP Holdings L.P. would result in a change in control of Enterprise Products GP.

(3) Dan Duncan LLC acquired beneficial ownership of these units in connection with the formation and initial public offering of Enterprise GP Holdings L.P. Dan Duncan LLC is owned by Mr. Duncan.

(4) As a result of control rights EPCO has a result of its general partner interest in the Employee Partnership, Mr. Duncan is deemed beneficial owner of the units owned by the Employee Partnership.

(5) In addition to the units owned by EPCO, Mr. Duncan is deemed to be the beneficial owner of the units owned by the Duncan Family 1998 Trust and the Duncan Family 2000 Trust, the beneficiaries of which are the shareholders of EPCO.

(6) These individuals are the named executive officers of Enterprise GP Holdings at December 31, 2005.

(7) The number of Enterprise Products Partners L.P. common units shown for Mr. Phillips includes 4,540 common units held by trusts for which he has disclaimed beneficial ownership.

(8) The number of Enterprise Products Partners L.P. common units shown for Mr. Andras includes 100,000 common units held by a trust for which he has disclaimed beneficial ownership.

(9) Cumulatively, this group s beneficial ownership amount includes 200,000 options to acquire common units of Enterprise Products Partners L.P. that were issued under the 1998 Plan. These options are exercisable within 60 days of the filing date of this report.

Securities Authorized for Issuance Under Our Equity Compensation Plans

In November 2005, we filed a registration statement covering the potential future issuance of 250,000 of our units in connection with a long-term incentive plan of EPCO (the 2005 Plan). The 2005 Plan was established to encourage directors of EPE Holdings and employees of EPCO that perform services for us to increase their ownership of our units and to develop a sense of proprietorship and personal involvement in our and Enterprise Product Partners business and financial success. The 2005 Plan provides for the future issuance of unit options, restricted units or phantom units (limited to 250,000 units). No awards have been issued under the 2005 Plan as of February 15, 2006.

The following table sets forth certain information as of December 31, 2005 regarding the 2005 Plan.

Plan Category	**Number of units to be issued upon exercise of outstanding awards (a)**	**Weighted-average exercise price of outstanding awards (b)**	**Number of units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)**
Equity compensation plans approved by unitholders:			
2005 Plan	-	-	250,000
Equity compensation plans not approved by EPD unitholders:			
None.	-	-	-
Total for equity compensation plans	-	-	250,000

The 2005 Plan is effective until the earlier of (i) all available units under the plan have been issued to participants, (ii) early termination of the 2005 Plan by EPCO or (iii) the tenth anniversary of the 2005 Plan, which is August 2015.

Securities Authorized for Issuance Under Enterprise Products Partners Equity Compensation Plans

The following table sets forth certain information as of December 31, 2005 regarding the 1998 Plan, under which common units of Enterprise Products Partners are authorized for issuance to EPCO s key employees and to directors of Enterprise Products GP through the exercise of unit options. In the context of the following table, EPD means Enterprise Products Partners L.P.

Plan Category	**Number of EPD units to be issued upon exercise of outstanding common unit options (a)**	**Weighted-average exercise price of outstanding common unit options (b)**	**Number of EPD units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)**
Equity compensation plans approved by unitholders:			
EPD unit options issued under 1998 Plan	2,082,000	$22.16	670,000
Equity compensation plans not approved by EPD unitholders:			
None.	-	-	-
Total for equity compensation plans [1]	2,082,000	$22.16	670,000

(1) Of the 2,082,000 unit options outstanding at December 31, 2005, 727,000 were immediately exercisable and an additional 25,000, 840,000, and 490,000 were exercisable in 2006, 2008 and 2009, respectively.

The 1998 Plan is effective until either all available common units under the plan have been issued to participants or the earlier termination of the 1998 Plan by EPCO. The 1998 Plan also provides for the issuance of 3,000,000 restricted common units, of which 2,203,764 remain authorized for issuance at December 31, 2005. During 2005, a total of 263,079 restricted common units were issued (net of forfeitures and vesting) to key employees of EPCO and our independent directors.

For additional information regarding our 2005 Plan and 1998 Plan and related equity awards, please read Notes 2 and 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

The following information summarizes our business relationships and related transactions with entities controlled by Dan L. Duncan during 2005. We have also provided information regarding our business relationships and transactions with unconsolidated affiliates and Shell.

For information regarding our related party transactions in general, please read Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with Enterprise Products Partners

We own 100% of the general partner interest and 13,454,498 common units of Enterprise Products Partners. We received $82.7 million in cash distributions from Enterprise Products Partners in 2005 with respect to these ownership interests.

Relationship with EPCO and its other affiliates

Statement of Transactions with EPCO and affiliates during 2005. The following table presents a detailed statement of amounts we paid to EPCO and affiliates during 2005 by transaction category (dollars in thousands):

Revenues:	
Sales of NGL products	$ 275
Storage fees	36
Total revenues related to EPCO and affiliates	$ 311
Operating costs and expenses:	
Purchase of NGL products, including freight and storage	$ 94,982
Reimbursement of operating employee costs	193,253
Recognition of non-cash retained lease expense	2,112
Office space lease expense	2,036
Other	751
Total operating costs and expenses related to EPCO and affiliates	293,134
General and administrative costs:	
Reimbursement of overhead employee costs	39,152
Office space lease expense	1,217
Other	685
Total general and administrative costs related to EPCO and affiliates	41,054
Total costs and expenses related to EPCO and affiliates	$ 334,188
Interest expense	$ 15,306
Cash distributions paid to EPCO by us and Enterprise Products Partners	$ 243,904
Non-cash expense amount recognized by Enterprise Products Partners in connection with Employee Partnership equity awards	$ 2,064

General. We have an extensive and ongoing relationship with EPCO and its other affiliates, which include the following significant entities:

- EPCO and its private company subsidiaries;
- EPE Holdings, our general partner;
- the Employee Partnership; and
- TEPPCO and its general partner, which are controlled by affiliates of EPCO

Unless noted otherwise, our agreements with EPCO are not the result of arm s length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Enterprise Products Partners was formed in 1998 to own and operate certain NGL assets contributed to it by EPCO. EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of EPE Holdings and Enterprise Products GP. Mr. Duncan owns 50.4% of the voting stock of EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan s family.

At February 15, 2006, EPCO and its affiliates beneficially owned 76,900,603 (or 86.5%) of our outstanding units and 144,153,993 (or 36.9%) of Enterprise Products Partners common units. In January 2005, an affiliate of EPCO acquired 13,454,498 common units of Enterprise Products Partners and a 9.9% membership interest in Enterprise Products GP from El Paso for approximately $425 million in cash. As a result of this transaction and until August 2005, EPCO and certain of its affiliates owned 100% of the membership interests of Enterprise Products GP. An affiliate of EPCO is the sole member of EPE Holdings.

In August 2005, affiliates of EPCO contributed their member interests in Enterprise Products GP and the 13,454,498 common units of Enterprise Products Partners they acquired from El Paso to us. As a result of this contribution, we are the sole member of Enterprise Products GP and own 3.4% of the limited partner interests of Enterprise Products Partners.

The principal business activity of EPE Holdings and Enterprise Products GP is to act as the managing partners of Enterprise GP Holdings L.P. and Enterprise Products Partners L.P., respectively. The executive officers and certain of the directors of EPE Holdings and Enterprise Products GP are employees of EPCO (see Item 10 of this annual report on Form 10-K).

Apart from the rights Enterprise Products GP owns with respect to its general partner interest in Enterprise Products Partners, Enterprise Products GP does not receive any compensation for services provided to Enterprise Products Partners. Likewise, EPE Holdings does not receive any compensation for services provided to us.

We, EPE Holdings, Enterprise Products Partners, and Enterprise Products GP are separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO depends on the cash distributions it receives from us, Enterprise Products Partners and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received a combined $243.9 million in cash distributions from us and Enterprise Products Partners during 2005.

The ownership interests in us and Enterprise Products Partners that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an EPCO affiliate. EPCO s credit facility contains customary and other events of default relating to EPCO and certain affiliates, including us, Enterprise Products Partners and TEPPCO. In the event of a default under this credit facility, a change in control of us or Enterprise Products Partners could occur.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. During 2005, we paid this affiliate $17.6 million for such services. In addition, we buy from and sell certain NGL products to another affiliate of EPCO at market-related prices in the normal course of business. During 2005, our revenues from this affiliate were $0.3 million and our purchases from this affiliate were $61 million.

We also lease office space in various buildings from affiliates of EPCO related to our corporate headquarters in Houston, Texas. During 2005, our operating lease expense recorded in connection with these agreements was $3.3 million. The rental rates in these agreements approximate market rates.

Relationship with TEPPCO. In February 2005, an affiliate of EPCO acquired 100% of the membership interests of Texas Eastern Products Pipeline Company, LLC (TEPPCO GP), the general partner of TEPPCO and 2,500,000 common units of TEPPCO for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. In June 2005, the employees of TEPPCO became EPCO employees. Enterprise Products Partners paid $17.2 million to TEPPCO during 2005 for NGL pipeline transportation and storage services. In addition, certain directors of Enterprise Products GP and Enterprise GP Holdings (Messrs. Bachmann, Creel and Fowler) were elected as additional directors of TEPPCO GP in February 2006.

In March 2005, the Bureau of Competition of the FTC delivered written notice to EPCO s legal advisor that it was conducting a non-public investigation to determine whether EPCO s acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with EPCO s purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and we intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets.

In February 2006, we and TEPPCO entered into a letter of intent related to the formation of a joint venture to expand TEPPCO s Jonah Gas Gathering System (the Jonah system) located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d. The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006. The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and the general partner of Enterprise Products Partners, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d. We expect this expansion to be completed in mid-2006.

Employee Partnership. In connection with the initial public offering of the parent company, EPCO formed the Employee Partnership to serve as an incentive arrangement for certain employees of EPCO through a profits interest in the Employee Partnership. EPCO serves as the general partner of the Employee Partnership. In connection with the closing of our initial public offering, EPCO Holdings, Inc., a wholly owned subsidiary of EPCO, borrowed $51 million under its credit facility and contributed the borrowings to its wholly-owned subsidiary, Duncan Family Interests, Inc. (Duncan Family Interests),

which, in turn, contributed $51 million to the Employee Partnership as a capital contribution with respect to its Class A limited partner interest. The Employee Partnership used the contributed funds to purchase 1,821,428 units directly from us at the initial public offering price. Certain EPCO employees, including all of EPE Holdings and Enterprise Products GP s executive officers other than Dan L. Duncan, have been issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of the Employee Partnership, the Employee Partnership will terminate at the earlier of five years following the closing of our initial public offering or a change in control of us or our general partner. The Employee Partnership has the following material terms with respect to distributions:

Distributions of Cashflow each quarter, 100% of the distributions from units held by the Employee Partnership will be distributed to Duncan Family Interests until it has received the Class A preferred return (as defined below), and any remaining distributions from the Employee Partnership will be distributed to the Class B limited partners. The Class A preferred return will equal 1.5625% per quarter, or 6.25% per annum, of Duncan Family Interest s capital base. Duncan Family Interest s capital base will equal $51 million, increased by any unpaid Class A preferred return from prior periods, and decreased by any distributions of sale proceeds to Duncan Family Interests as described below.

Liquidating Distributions Upon liquidation of the Employee Partnership, units having a fair market value equal to Duncan Family Interest s capital base will be distributed to Duncan Family Interests, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

Sale Proceeds If the Employee Partnership sells any units, the sale proceeds will be distributed to Duncan Family Interests and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in the Employee Partnership that are owned by EPCO employees are subject to forfeiture if the participating employee s employment with EPCO and its affiliates is terminated prior to the fifth anniversary of the closing of our initial public offering, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in the Employee Partnership will also lapse upon certain change of control events.

We and our general partner will not reimburse EPCO, the Employee Partnership or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to the Employee Partnership or the contribution of $51 million to the Employee Partnership or the purchase of the units by the Employee Partnership.

For the period that the Employee Partnership was in existence during 2005, EPCO accounted for this stock-based compensation arrangement using APB 25. Under APB 25, the value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights. EPCO s non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of each employee s services. During 2005, we recorded $2 million of non-cash compensation expense associated with the Employee Partnership. For additional information regarding the Employee Partnership, please read Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Administrative Services Agreement. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (ASA). We and our general partner, Enterprise Products Partners and its general partner, and TEPPCO and its general partner are parties to the ASA. The significant terms of the ASA are as follows:

EPCO will provide selling, general, administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

EPCO has allowed us to participate as named insureds in its overall insurance program with the associated costs being charged to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the retained leases). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our operating costs and expenses for 2005 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity s business and affairs).

The ASA addresses potential conflicts that may arise among Enterprise Products Partners, Enterprise Products GP, Enterprise GP Holdings L.P., EPE Holdings and the EPCO Group, which includes EPCO and its affiliates (excluding Enterprise Products GP, Enterprise Products Partners and its subsidiaries, Enterprise GP Holdings L.P. and EPE Holdings, and TEPPCO, TEPPCO GP and their controlled affiliates). The ASA provides, among other things, that:

if a business opportunity to acquire equity securities is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings, or us, then we will have the first right to pursue such opportunity. Equity securities are defined to include:

general partner interests (or securities which have characteristics similar to general partner interests) and incentive distribution rights or similar rights in publicly traded partnerships or interests in persons that own or control such general partner or similar interests (collectively, GP Interests) and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in persons that own or control such limited partner or similar interests (collectively, non-GP Interests); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

185

We will be presumed to desire to acquire the equity securities until such time as EPE Holdings advises the EPCO Group and Enterprise Products GP that we have abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the Audit and Conflicts Committee of EPE Holdings. If the purchase price is reasonably likely to be less than such threshold amount, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the Audit and Conflicts Committee of EPE Holdings. In the event that we abandon the acquisition and so notifies the EPCO Group and Enterprise Products GP, Enterprise Products Partners will have the second right to the pursue such acquisition. Enterprise Products Partners will be presumed to desire to acquire the equity securities until such time as Enterprise Products GP advises the EPCO Group that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to us, as described above but utilizing Enterprise Products GP s Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the acquisition and so notifies the EPCO Group, the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

- if any business opportunity not covered by the preceding bullet point is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or us, Enterprise Products Partners will have the first right to pursue such opportunity. Enterprise Products Partners will be presumed to desire to pursue the business opportunity until such time as Enterprise Products GP advises the EPCO Group and EPE Holdings that Enterprise Products Partners has abandoned the pursuit of such business opportunity. In the event that the purchase price or cost associated with the business opportunity is reasonably likely to exceed $100 million, the decision to decline the business opportunity will be made by the Chief Executive Officer of Enterprise Products GP after consultation with and subject to the approval of the Audit and Conflicts Committee of Enterprise Products GP. If the purchase price or cost is reasonably likely to be less than such threshold amount, the Chief Executive Officer of Enterprise Products GP may make the determination to decline the business opportunity without consulting Enterprise Products GP s Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the business opportunity and so notifies the EPCO Group and EPE Holdings, we will have the second right to the pursue such business opportunity. We will be presumed to desire to pursue such business opportunity until such time as EPE Holdings advises the EPCO Group that we have abandoned the pursuit of such business opportunity. In determining whether or not to pursue the business opportunity, we will follow the same procedures applicable to Enterprise Products Partners, as described above but utilizing EPE Holdings Chief Executive Officer and Audit and Conflicts Committee. In the event that we abandon the business opportunity and so notifies the EPCO Group, the EPCO Group may pursue the business opportunity without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings, or us have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates, and TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or us.

The ASA also outlines an overall corporate governance structure and provides policies and procedures to address potential conflicts of interest among the parties to the ASA, including protection of the confidential information of each party from the other parties and the sharing of EPCO employees between the parties. Specifically, the ASA provides, among other things, that:

- there shall be no overlap in the independent directors of Enterprise Products GP, EPE Holdings and TEPPCO GP;

there shall be no sharing of EPCO employees performing commercial and development activities involving certain defined potential overlapping assets between us, Enterprise Products Partners, and EPCO and its other affiliates (excluding TEPPCO and subsidiaries) on one hand and TEPPCO and its subsidiaries and TEPPCO GP on the other hand; and

certain screening procedures are to be followed if an EPCO employee performing commercial and development activities becomes privy to commercial information relating to a potential overlapping asset of any entity for which such employee does not perform commercial and development activities.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. Since we or EPCO and its other affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here.

The following information summarizes significant related party transaction amounts with our unconsolidated affiliates during 2005:

We sold $318.8 million of natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005.

We paid $26 million to Promix for the transportation, storage and fractionation of NGLs during 2005. In addition, we sold $25.8 million of natural gas to Promix for its plant fuel requirements during 2005.

We perform management services for certain of our unconsolidated affiliates. During 2005, these affiliates paid us $8.3 million for such services.

We occasionally pay for construction labor costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets. We are fully reimbursed for such amounts. During 2005, we made $0.6 million of such payments on behalf of unconsolidated affiliates.

Relationship with Shell

At February 15, 2006, Shell owned approximately 7.5% of the limited partner interests of Enterprise Products Partners. During 2005, our revenues from Shell totaled $549.1 million and our expenses with Shell were $852 million. Historically, Shell has been one of our largest customers. For the years ended December 31, 2005, 2004 and 2003, Shell accounted for 4.5%, 6.5% and 5.5%, respectively, of our consolidated revenues. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell Processing Agreement and the purchase of NGL products from Shell. We also lease from Shell its 45.4% interest in one of our propylene fractionation facilities located in Mont Belvieu, Texas.

A significant contract affecting our natural gas processing business is the Shell Processing Agreement, which grants us the right to process Shell s (or an assignee s) current and future production within state and federal waters of the Gulf of Mexico. The Shell Processing Agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019.

In connection with its March 2005 universal registration statement, Enterprise Products Partners registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units owned by a third party, Kayne Anderson MLP Investment Company, which had been acquired from Shell. Enterprise

Products Partners was obligated to register the resale of these common units under a registration rights agreement it executed with Shell in September 1999.

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

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, Deloitte & Touche) as our principal accountant. The following table summarizes fees we have paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31,	
	2005	**2004**
Enterprise GP Holdings L.P.		
Audit Fees [1]	$ 867	$ 15
Audit-Related Fees [2]	n/a	n/a
Tax Fees [3]	9	n/a
All Other Fees [4]	n/a	n/a
Enterprise Products Partners L.P.		
Audit Fees [1]	$ 4,892	$ 5,227
Audit-Related Fees [2]	14	32
Tax Fees [3]	407	586
All Other Fees [4]	n/a	n/a

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report on Form 10-K.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements, partnership tax planning and property tax assistance.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last two years.

The Audit and Conflicts Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the Audit and Conflicts Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the Audit and Conflicts Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The Audit and Conflicts Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial pre-approved fee amount). As part of these discussions, the Audit and Conflicts Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as AICPA rules. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the Audit and Conflicts Committee to increase the approved amount and the reasons for the requested increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the Audit and Conflicts Committee is provided a schedule showing Deloitte & Touche s pre-approved amounts compared to actual fees billed for each of the primary service categories. The Audit and Conflicts Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

For Deloitte & Touche to maintain its independence, we are prohibited from using Deloitte & Touche to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The Audit and Conflicts Committee s pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this annual report. For a listing of these statements and accompanying footnotes, please see *Index to Financial Statements* on page 85 of this annual report.

(a)(2) Financial Statement Schedules

Schedule II Valuation and Qualifying Accounts is included on page 164 of this annual report.

All schedules, except the one listed above, have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Exhibit Number	Exhibit*
2.1	Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated September 22, 2000 (incorporated by reference to Exhibit 10.1 to Enterprise Products Partners Form 8-K filed September 26, 2000).
2.2	Purchase and Sale Agreement dated January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (incorporated by reference to Exhibit 10.1 to Enterprise Products Partners Form 8-K filed February 8, 2002.)
2.3	Purchase and Sale Agreement dated January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers and Enterprise Products Operating L.P. as Buyer (incorporated by reference to Exhibit 10.2 to Enterprise Products Partners Form 8-K filed February 8, 2002).
2.4	Purchase Agreement by and between E-Birchtree, LLC and Enterprise Products Operating L.P. dated July 31, 2002 (incorporated by reference to Exhibit 2.2 to Enterprise Products Partners Form 8-K filed August 12, 2002).
2.5	Purchase Agreement by and between E-Birchtree, LLC and E-Cypress, LLC dated July 31, 2002 (incorporated by reference to Exhibit 2.1 to Enterprise Products Partners Form 8-K filed August 12, 2002).
2.6	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Enterprise Products Partners Form 8-K filed December 15, 2003).
2.7	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Enterprise Products Partners Form 8-K filed September 7, 2004).

2.8	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Enterprise Products Partners Form 8-K filed December 15, 2003).
2.9	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Enterprise Products Partners Form 8-K filed April 21, 2004).

2.10	Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003, (incorporated by reference to Exhibit 2.3 to Enterprise Products Partners Form 8-K filed December 15, 2003).
2.11	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C. adopted by Enterprise Products GTM, LLC as of September 30, 2004 (incorporated by reference to Exhibit 2.11 to Registration Statement on Enterprise Products Partners Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
2.12	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Enterprise Products Partners Form 8-K filed December 15, 2003).
3.1	First Amended and Restated Agreement of Limited Partnership of Enterprise GP Holdings L.P., dated as of August 29, 2005 (incorporated by reference to Exhibit 3.1 to Enterprise GP Holdings Form 10-Q filed November 4, 2005).
3.2	Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated as of August 29, 2005 (incorporated by reference to Exhibit 3.2 to Enterprise GP Holdings Form 8-K filed September 1, 2005).
3.3	Certificate of Limited Partnership of Enterprise GP Holdings L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed July 21, 2005).
3.4	Certificate of Formation of EPE Holdings, LLC (incorporated by reference to Exhibit 3.2 to Amendment No. 2 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed July 21, 2005).
3.5	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Enterprise Products Partners Form 8-K filed August 10, 2005).
3.6	Third Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of August 29, 2005 (incorporated by reference to Exhibit 3.1 to Enterprise Products Partners Form 8-K filed September 1, 2005).
3.7	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003)(incorporated by reference to Exhibit 3.1 to Enterprise Products Partners Form 8-K filed July 1, 2005).
3.8	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Enterprise Products Partners Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.9	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Enterprise Products Partners Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed March 10, 2000).
4.2	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Enterprise Products Partners Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.3	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Enterprise Products Partners Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Enterprise Products

	Partners Form 10-K filed March 31, 2003).
4.5	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Enterprise Products Partners Form 10-K filed March 31, 2003).
4.6	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed January 25, 2001).
4.7	Specimen Unit certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 3 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed August 11, 2005).
4.8	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.9	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit E to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.10	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit C to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.11	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed September 15, 2003).
4.12	Agreement dated as of March 4, 2005 among Enterprise Products Partners L.P., Shell US Gas & Power LLC and Kayne Anderson MLP Investment Company (incorporated by reference to Exhibit 4.31 to Enterprise Products Partners Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.13	$750 Million Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed on August 30, 2004).
4.14	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.13, above (incorporated by reference to Exhibit 4.2 to Enterprise Products Partners Form 8-K filed on August 30, 2004).
4.15	First Amendment dated October 5, 2005, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, CitiBank, N.A. and JPMorgan Chase Bank, as CO-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.3 to Enterprise Products Partners Form 8-K filed on October 7, 2005).
4.16	$2.25 Billion 364-Day Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citicorp North America, Inc. and Lehman Commercial Paper Inc., as Co-Syndication Agents, JPMorgan Chase Bank, UBS Loan Finance LLC and Morgan Stanley Senior Funding, Inc., as Co-Documentation Agents, Wachovia Capital Markets, LLC, Citigroup Global Markets Inc. and Lehman Brothers Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.3 to Enterprise Products Partners Form 8-K filed on August 30, 2004).
4.17	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.16, above (incorporated by reference to Exhibit 4.4 to Enterprise Products Partners Form 8-K filed on August 30, 2004).
4.18	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed on October 6, 2004).
4.19	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating

	L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Enterprise Products Partners Form 8-K filed on October 6, 2004).
4.20	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Enterprise Products Partners Form 8-K filed on October 6, 2004).
4.21	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Enterprise Products Partners Form 8-K filed on October 6, 2004).
4.22	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Enterprise Products Partners Form 8-K filed on October 6, 2004).
4.23	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Enterprise Products Partners Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.24	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Enterprise Products Partners Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.25	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Enterprise Products Partners Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.26	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Enterprise Products Partners Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.27	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Enterprise Products Partners Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.28	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Enterprise Products Partners Form 8-K filed on March 3, 2005).
4.29	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Enterprise Products Partners Form 8-K filed on March 3, 2005).
4.30	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Enterprise Products Partners Form 10-Q filed on November 4, 2005).
4.31	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Enterprise Products Partners Form 10-Q filed on November 4, 2005).
4.32	Registration Rights Agreement dated as of March 2, 2005, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.6 to Enterprise Products Partners Form 8-K filed on March 3, 2005).
4.33	Assumption Agreement dated as of September 30, 2004 between Enterprise Products Partners L.P. and GulfTerra Energy Partners, L.P. relating to the assumption by Enterprise of GulfTerra's obligations under the GulfTerra Series F2 Convertible Units (incorporated by reference to Exhibit 4.4 to Enterprise Products Partners Form 8-K/A-1 filed on October 5, 2004).
4.34	Statement of Rights, Privileges and Limitations of Series F Convertible Units, included as Annex A to Third Amendment to the Second Amended and Restated Agreement of Limited Partnership of GulfTerra Energy Partners, L.P., dated May 16, 2003 (incorporated by reference to Exhibit 3.B.3 to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).

4.35	Unitholder Agreement between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. dated May 16, 2003 (incorporated by reference to Exhibit 4.L to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.36	Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra s Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.1 to GulfTerra s 2002 First Quarter Form 10-Q); Second Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.2 to GulfTerra s 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (filed as Exhibit 4.E.3 to GulfTerra s 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (filed as Exhibit 4.E.1 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.E.2 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.E.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.37	Seventh Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.E.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.38	Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra s Current Report of Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.1.1 to GulfTerra s Current Report on Form 8-K dated March 19, 2003); Second Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.1.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.39	Third Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.1.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.40	Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (filed as Exhibit 4.K to GulfTerra s Quarterly Report on Form 10-Q dated May 15, 2003); First Supplemental Indenture dated as of June 30, 2003 (filed as Exhibit 4.K.1 to GulfTerra s 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.41	Second Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.K.1 to GulfTerra s Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.42	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed on July 1, 2005).
4.43	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Enterprise Products Partners Form 10-Q filed November 4, 2005).
4.44	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Enterprise Products Partners Form 10-Q filed November 4, 2005).
4.45	Note Purchase Agreement dated as of December 15, 2005 among Cameron Highway Oil Pipeline Company and the Note Purchasers listed therein (incorporated by reference to Exhibit 4.1 to Enterprise Products Partners Form 8-K filed December 21, 2005.)
4.46	Credit Agreement, dated as of August 29, 2005, by and among Enterprise GP Holdings L.P., the lenders party thereto, Lehman Commercial Paper Inc., as Co-Administrative Agent, Citicorp North America, Inc., as Co-Administrative Agent, The Bank of Nova Scotia, as Syndication Agent, and SunTrust Bank, as Documentation Agent (incorporated by reference to Exhibit 4.1 to Enterprise GP Holdings Form 8-K filed September 1, 2005).
4.47	Amended and Restated Credit Agreement dated January 11, 2005 among Enterprise GP Holdings L.P., as the Borrower, Citicorp North America, Inc., as Administrative Agent, Lehman Commercial Paper Inc., as Syndication Agent, Citibank N.A., as Issuing Bank, and the various

	other lenders party thereto (incorporated by reference to Exhibit 4.1 to Enterprise GP Holdings Form 8-K filed January 13, 2006).
10.1	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Enterprise Products Partners Registration Statement on Form S-1/A filed July 8, 1998).
10.2	Seventh Amendment to Conveyance of Gas Processing Rights, dated as of April 1, 2004 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources Inc., Shell Land & Energy Company, Shell Frontier Oil & Gas Inc. and Shell Gulf of Mexico Inc. (incorporated by reference to Exhibit 10.1 to Enterprise Products Partners Form 8-K filed April 26, 2004).
10.3***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of April 8, 2004 (incorporated by reference to Appendix B to Notice of Written Consent dated April 22, 2004, filed April 22, 2004 by Enterprise Products Partners).
10.4***	Form of Option Grant Award under 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to Enterprise Products Partners Form S-8 Registration Statement, Reg. No. 333-115633, filed May 19, 2004).
10.5***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Enterprise Products Partners Form S-8 Registration Statement, Reg. No. 333-115633, filed May 19, 2004).
10.6***	1998 Omnibus Compensation Plan of GulfTerra Energy Partners, L.P., Amended and Restated as of January 1, 1999 (incorporated by reference to Exhibit 10.9 to Form 10-K for the year ended December 31, 1998 of GulfTerra Energy Partners, L.P., file no. 001-11680); Amendment No. 1, dated as of December 1, 1999 (incorporated by reference to Exhibit 10.8.1 to Form 10-Q for the quarter ended June 30, 2000 of GulfTerra Energy Partners, L.P., file no. 001-116800); Amendment No. 2 dated as of May 15, 2003 (incorporated by reference to Exhibit 10.M.1 to Form 10-Q for the quarter ended June 30, 2003 of GulfTerra Energy Partners, L.P., file no. 001-11680).
10.7	Third Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated August 15, 2005, but effective as of February 24, 2005 (incorporated by reference to Exhibit 10.1 to Enterprise Products Partners Form 8-K filed August 22, 2005).
10.8***	EPE Unit L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.2 to Enterprise GP Holdings Current Report on Form 8-K on September 1, 2005).
10.9***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Amendment No. 3 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed on August 11, 2005).
10.10***	Form of Restricted Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to Amendment No. 3 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed on August 11, 2005).
10.11***	Form of Phantom Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to Amendment No. 3 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed on August 11, 2005).
10.12	Contribution, Conveyance and Assumption Agreement, dated as of August 29, 2005, by and among Enterprise GP Holdings L.P., EPE Holdings, LLC, Dan Duncan LLC, Duncan Family Interests, Inc., DFI GP Holdings L.P. and DFI Holdings, LLC (incorporated by reference to Exhibit 10.1 to Enterprise GP Holdings Form 8-K filed September 1, 2005).
10.13	$370 million note owed by Enterprise Products GP, LLC to Dan Duncan LLC (incorporated by reference to Amendment No. 3 to Enterprise GP Holdings Form S-1 Registration Statement, Reg. No. 333-124320, filed August 11, 2005).
10.14	$160 million note assumed by Enterprise GP Holdings L.P. and payable to EPCO, Inc. (incorporated by reference to Enterprise GP Holdings Form 10-Q filed November 4, 2005).
10.15	Unit Purchase Agreement dated August 23, 2005, between Enterprise GP Holdings L.P. and EPE Unit L.P. (incorporated by reference to Exhibit 1.2 to Enterprise GP Holdings Form 8-K filed September 1, 2005).

10.16	Waiver of Provisions of the Conflicts Policies and Procedures of the Third Amended and Restated Administrative Services Agreement dated February 23, 2006 but effective as of February 13, 2006 (incorporated by reference to Exhibit 10.12 to Enterprise Products Partners Form 10-K filed February 27, 2006).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2005, 2004, 2003, 2002 and 2001.
18.1	Letter regarding Change in Accounting Principles dated May 4, 2004 (incorporated by reference to Exhibit 18.1 to Enterprise Products Partners' Form 10-Q filed May 10, 2004).
21.1#	List of subsidiaries.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise GP Holdings L.P. for the December 31, 2005 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise GP Holdings L.P. for the December 31, 2005 annual report on Form 10-K.
32.1#	Section 1350 certification of Michael A. Creel for the December 31, 2005 annual report on Form 10-K.
32.2#	Section 1350 certification of W. Randall Fowler for the December 31, 2005 annual report on Form 10-K.

* With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file numbers for Enterprise GP Holdings L.P. and Enterprise Products Partners L.P. are 1-32610 and 1-14323, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

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 on February 27, 2006.

ENTERPRISE GP HOLDINGS L.P.

(A Delaware Limited Partnership)

By: EPE Holdings, LLC, as general partner

By: */s/ Michael J. Knesek* Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer of the general partner

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 indicated below on February 27, 2006.

Signature	**Title (Position with EPE Holdings, LLC)**
/s/ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Michael A. Creel Michael A. Creel	Director, President and Chief Executive Officer
/s/ Richard H. Bachmann Richard H. Bachmann	Director, Executive Vice President, Chief Legal Officer and Secretary
/s/ W. Randall Fowler W. Randall Fowler	Director, Senior Vice President and Chief Financial Officer
/s/ Robert G. Phillips Robert G. Phillips	Director
/s/ O.S. Andras O.S. Andras	Director
/s/ Charles E. McMahen Charles E. McMahen	Director
/s/ Edwin E. Smith Edwin E. Smith	Director
/s/ W. Matt Ralls W. Matt Ralls	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

Index to Exhibits

The following exhibits have been filed with this report. The other exhibits required to be filed with this annual report have been incorporated by reference as indicated in the exhibit table found under Item 15 of this report beginning on page 190.

Exhibit Number	Description of Exhibit
12.1	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2005, 2004, 2003, 2002 and 2001.
21.1	List of subsidiaries.
23.1	Consent of Deloitte & Touche LLP.
31.1	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise GP Holdings L.P. for the December 31, 2005 annual report on Form 10-K.
31.2	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise GP Holdings L.P. for the December 31, 2005 annual report on Form 10-K.
32.1	Section 1350 certification of Michael A. Creel for the December 31, 2005 annual report on Form 10-K.
32.2	Section 1350 certification of W. Randall Fowler for the December 31, 2005 annual report on Form 10-K.