ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
February 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2006

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: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1100 Louisiana, 10th Floor, Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

(713) 381-6500
(Registrant s Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

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

Securities 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 þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

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

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 þ Accelerated filer o Non-accelerated filer o

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

Yes o No þ

The aggregate market value of the common units of *Enterprise Products Partners L.P.* (EPD) held by non-affiliates at June 30, 2006, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange on June 30, 2006, was approximately $6.6 billion. This figure excludes common units beneficially owned by certain affiliates, including (i) Dan L. Duncan, (ii) Enterprise GP Holdings L.P. and (iii) certain trusts established for the benefit of Mr. Duncan s family. There were 432,408,430 common units of EPD outstanding at February 1, 2007.

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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to *we*, *us*, *our* or *Enterprise Products Partners* are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries, including Duncan Energy Partners.

References to *Operating Partnership* mean Enterprise Products Operating L.P., which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to *Duncan Energy Partners* or DEP mean Duncan Energy Partners L.P., which is a publicly traded, consolidated subsidiary of the Operating Partnership and completed its initial public offering in February 2007.

References to *Enterprise Products GP* mean Enterprise Products GP, LLC, which is our general partner.

References to *Enterprise GP Holdings* mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, which owns Enterprise Products GP.

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

References to *TEPPCO* mean TEPPCO Partners, L.P.; a publicly traded Delaware limited partnership, which is an affiliate of us.

References to *TEPPCO GP* mean Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and owned by a private company subsidiary of EPCO, Inc.

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

References to *Employee Partnerships* mean EPE Unit L.P. and EPE Unit II, L.P., collectively, which are private company affiliates of EPCO. References to EPE Unit I and EPE Unit II refer to EPE Unit L.P. and EPE Unit II, L.P., respectively.

We, the Operating Partnership, Duncan Energy Partners, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

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 our general partner, 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 operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner 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.

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PART I

Items 1 and 2. *Business and Properties*.

General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), crude oil, and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through our Operating Partnership. Our principal executive offices are located at 1100 Louisiana, 10th Floor, Houston, Texas 77002 and our telephone number is (713) 381-6500.

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPD. We are owned 98% by our limited partners and 2% by our general partner, Enterprise Products GP. Our general partner is owned by a publicly traded affiliate, Enterprise GP Holdings, the common units of which are listed on the NYSE under the ticker symbol EPE.

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

In September 2006, we formed Duncan Energy Partners, a Delaware limited partnership, to acquire, own and operate a diversified portfolio of midstream energy assets from us. Duncan Energy Partners completed its initial public offering of 14,950,000 common units in February 2007. The common units of Duncan Energy Partners are listed on the NYSE under the ticker symbol DEP. For additional information regarding Duncan Energy Partners, see *Recent Developments* within this Item 1.

Business Strategy

We operate an integrated network of midstream energy assets that includes natural gas gathering, processing, transportation and storage; NGL fractionation (or separation), transportation, storage and import and export terminalling; crude oil transportation; offshore production platform services; and petrochemical pipeline and services. NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and as fuel by industrial and residential users. Our business strategy is to:

§ capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountain region, U.S. Gulf Coast and Gulf of Mexico;

§ maintain a balanced and diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;

§ share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth projects or purchase the project s end products; and

§ increase fee-based cash flows by investing in pipelines and other fee-based businesses.

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As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. For information regarding our growth capital projects, see *Capital Spending* included under Item 7 of this annual report.

Financial Information by Business Segment

For information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Recent Developments

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.3 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,371,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,510 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,371,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under our Multi-Year Revolving Credit Facility.

In summary, we contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

§ *Mont Belvieu Caverns, LLC* (Mont Belvieu Caverns), a recently formed subsidiary, which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;

§ *Acadian Gas, LLC* (Acadian Gas), which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns a 49.5% equity interest in Evangeline Gas Pipeline, L.P. (Evangeline);

§ *Sabine Propylene Pipeline L.P.* (Sabine Propylene), which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;

§ *Enterprise Lou-Tex Propylene Pipeline L.P.* (Lou-Tex Propylene), which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and

§ *South Texas NGL Pipelines, LLC* (South Texas NGL), a recently formed subsidiary, which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition, to the 34% ownership interest we retained in each of these entities, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners outstanding common units. Our Operating Partnership directs the business operations of Duncan Energy Partners through its ownership and control of the general partner of Duncan Energy Partners.

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The formation of Duncan Energy Partners had no effect on our financial statements at December 31, 2006. For financial reporting purposes, the consolidated financial statements of Duncan Energy Partners will be consolidated into those of our own. Consequently, the results of operations of Duncan Energy Partners will be a component of our business segments. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners will reflect our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners.

The public owners of Duncan Energy Partners common units will be presented as a noncontrolling interest in our consolidated financial statements beginning in February 2007. The public owners of Duncan Energy Partners have no direct equity interests in us as a result of this transaction. The borrowings of Duncan Energy Partners will be presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

§ We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;

§ We buy natural gas from and sell natural gas to Acadian Gas in connection with our normal business activities; and

§ We are the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners in the near term and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions to Duncan Energy Partners.

For information regarding our other recent developments, see *Overview of Business Recent Developments* included under Item 7 of this annual report, which is incorporated by reference into this Item 1.

For recent developments involving releases of ammonia from a third-party pipeline operated by the Operating Partnership through an indirect wholly owned subsidiary, see Item 3 of this annual report.

Segment Discussion

Our midstream energy 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:

§ 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 technologies 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, see Item 1A 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, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see *Regulation* and *Environmental and Safety Matters* included within this Item 1.

Our revenues are derived from a wide customer base. During 2006 and 2005, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.1% and 6.8%, respectively, of our consolidated revenues. During 2004, our largest customer was Shell Oil Company and its affiliates (Shell), which accounted for 6.5% of our consolidated revenues.

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 decatherms
MMBbls	=	million barrels
MMBtus	=	million British thermal units
MMcf	=	million cubic feet
Mcf	=	thousand cubic feet
TBtu	=	trillion British thermal units

The following discussion of our business segments provides information regarding our principal plants, pipelines and other assets. For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 of this annual report.

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 13,295 miles and related storage facilities including our Mid-America Pipeline System 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 23 processing plants located in Texas, Louisiana, Mississippi, New Mexico and Wyoming. 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 petrochemical and motor gasoline production 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 natural gas processing plants are higher than the incremental value of the NGL products that would be extracted from a stream of natural gas, 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 sale of the mixed NGLs we extract on the producer s 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 earn and take title to 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, our 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 13,295 miles of NGL pipelines, 162 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 charge customers monthly storage reservation fees to reserve a specific storage capacity in our underground caverns. The customers pay reservation fees based on the quantity of capacity reserved rather than on the amount of reserved capacity utilized. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility. Accordingly, the profitability of our storage operations is dependent upon the level of capacity reserved by our customers, the volume of product injected and withdrawn from our underground caverns 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 for delivery 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 payments. 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 seven 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.

Extraction of mixed NGLs by natural 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 fee-based customers generally retain title to the NGLs that we process for them.

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.

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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 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.

Properties. The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 5, 2007.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100%	7,378	
Dixie Pipeline	South and Southeastern U.S.	74.2%(1)	1,370	
Seminole Pipeline	Texas	90% (2)	1,326	
EPD South Texas NGL System	Texas	100%	1,039	
Louisiana Pipeline System	Louisiana	Various(3)	612	
Promix NGL Gathering System	Louisiana	50%	362	
DEP South Texas NGL Pipeline System	Texas	100%(4)	286	
Houston Ship Channel	Texas	100%	266	
Lou-Tex NGL	Texas, Louisiana	100%	204	
Others (5 systems) (5)	Alabama, Louisiana, Mississippi	Various	452	
Total miles			13,295	
NGL and related product storage facilities by state:				
Texas (6)				125.0
Louisiana				16.6
Mississippi				10.9
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, Oklahoma, Utah)				9.6
Total capacity (7)				162.1

(1) We hold a 74.2% interest in this system through a majority owned subsidiary, Dixie Pipeline Company (Dixie). This reflects our acquisition of an additional 8.3% interest in Dixie in December 2006.

(2) We hold a 90% interest in this system through a

majority owned subsidiary, Seminole Pipeline Company (Seminole).

(3) Of the 612 total miles for this system, we own 100% of 559 miles and 43.5% of the remaining 53 miles.

(4) Reflects consolidated ownership of this system by the Operating Partnership (34%) and Duncan Energy Partners (66%).

(5) 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, L.L.C. (VESCO), an equity investment of ours.

(6) The amount shown for Texas includes 33 underground caverns with an aggregate

useable storage capacity of approximately 100 MMBbls that we own jointly with Duncan Energy Partners. These caverns are located in Mont Belvieu, Texas.

(7) The 162.1 MMBbls of total useable storage capacity includes 21.3 MMBbls held under operating leases. The leased facilities are located in Texas, Louisiana and Kansas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 1,450 MBPD, 1,360 MBPD and 1,343 MBPD during the years ended December 31, 2006, 2005 and 2004, respectively.

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 2,568-mile Rocky Mountain pipeline, the 2,771-mile Conway North pipeline and the 2,039-mile Conway South pipeline. This system covers thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. 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. The Mid-America Pipeline System interconnects 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.

During 2006, approximately 54% of the volumes transported on the Mid-America Pipeline System were 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 Greater 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. This system operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

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

§ The *EPD South 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 between Corpus Christi and Houston, Texas and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

§ The *Louisiana Pipeline System* is a network of 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 an NGL fractionator owned by K/D/S Promix, L.L.C. (Promix). This gathering system is an integral part of the Promix NGL fractionation facility. Our ownership interest in this pipeline is held indirectly through our equity method investment in Promix.

§ The *DEP South Texas NGL Pipeline System* transports NGLs from our Shoup and Armstrong fractionation facilities in south Texas to Mont Belvieu, Texas. This system became operational in January 2007. We purchased 220 miles of this pipeline from ExxonMobil Pipeline Company in August 2006. In addition, we lease an 11-mile segment of this pipeline system from TEPPCO. The remaining 55 miles of this pipeline were either acquired from TEPPCO (10 miles) or constructed by us (45 miles).

We contributed a direct 66% equity interest in South Texas NGL, our subsidiary that owns the DEP South Texas NGL Pipeline System, to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct interest in South Texas NGL. For additional information regarding this subsequent event, see *Recent Developments* within this Item 1.

§ 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.

In addition to the pipelines identified above, we have begun construction on the Meeker pipeline in the Piceance Basin area of western Colorado. This new 50-mile pipeline will transport mixed NGLs from our Meeker natural gas processing facility to the Mid-America Pipeline System.

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 NGLs and petrochemical products for us and our customers. Our underground storage facilities include locations in Arizona, Kansas and Utah that were acquired in July 2005. We operate these facilities, with the exception of certain storage locations operated for us by a third party in Louisiana and Mississippi.

We contributed a direct 66% equity interest in our recently formed subsidiary, Mont Belvieu Caverns, to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct interest in Mont Belvieu Caverns.

Mont Belvieu Caverns owns 33 underground storage caverns with an aggregate underground storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above-ground storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast.

The following table summarizes the significant natural gas processing and NGL fractionation assets of our NGL Pipelines & Services business segment at February 5, 2007.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
Natural gas processing facilities:						
Toca	Louisiana	61.4%	0.66	1.10		
Chaco	New Mexico	100%	0.65	0.65		
Pioneer (2)	Wyoming	100%	0.60	0.60		
Yscloskey	Louisiana	31.1%	0.58	1.85		
North Terrebonne	Louisiana	43.5%	0.57	1.30		
Calumet	Louisiana	31.2%	0.50	1.60		
Neptune	Louisiana	66%	0.43	0.65		
Pascagoula	Mississippi	40%	0.40	1.50		
Thompsonville	Texas	100%	0.30	0.30		
Shoup	Texas	100%	0.29	0.29		
Gilmore	Texas	100%	0.26	0.26		
Armstrong	Texas	100%	0.25	0.25		
Matagorda	Texas	100%	0.25	0.25		
Others (10 facilities) (3)	Texas, New Mexico, Louisiana	Various (4)	1.16	4.32		
Total processing capacities			6.90	14.92		
NGL fractionation facilities:						
Mont Belvieu	Texas	75%			178	230
Shoup and Armstrong	Texas	100%			87	87
Norco	Louisiana	100%			75	75
Promix	Louisiana	50%			73	145
BRF	Louisiana	32.2%			19	60
Tebone	Louisiana	43.5%			12	30
Total plant capacities					444	627

(1) The approximate net natural gas processing and NGL fractionation 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.

(2) We acquired the Pioneer facility from TEPPCO in March 2006 and subsequently increased the processing capacity from 0.3 Bcf/d to 0.6 Bcf/d.

(3) Includes our Venice, Blue Water, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin and Carlsbad facilities located in New Mexico; and San Martin, Delmita, Sonora and Indian Springs facilities located in Texas. We acquired the Indians Springs facility in January 2005. Our ownership in the Venice plant is through our 13.1% equity method

investment in VESCO.

(4) Our ownership in these facilities ranges from 7.4% to 100%.

At the core of our natural gas processing business are 23 processing plants located in Texas, Louisiana, Mississippi, New Mexico and Wyoming. 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 from gathering pipelines. We operate the Toca, Chaco, North Terrebonne, Calumet, Neptune, Carlsbad and Pioneer plants and all of the Texas facilities. In addition to the natural gas processing plants noted above, we have begun construction on the Meeker facility and a new natural gas processing facility adjacent to our existing Pioneer plant. The Meeker facility will be constructed in the Piceance Basin of western Colorado and will have the capacity to process 1.7 Bcf/d of natural gas. Our new Pioneer natural gas processing plant located in Opal, Wyoming will have a natural gas processing capacity of 0.75 Bcf/d. On a weighted-average basis, utilization rates for these assets were 56%, 53% and 61% during the years ended December 31, 2006, 2005 and 2004, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 830 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 and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, North Carolina 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.

§ 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 located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Yscloskey, Pascagoula and Toca facilities.

§ The *Promix* NGL fractionation facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Calumet, Neptune, Burns Point and Pascagoula facilities. In addition to the 362-mile Promix NGL Gathering System, Promix owns five NGL storage caverns and a barge loading facility that is integral to its operations.

§ Our *Shoup* and *Armstrong* NGL fractionation facilities fractionate mixed NGLs supplied by our south Texas natural gas processing plants. The Shoup and Armstrong facilities supply NGLs transported by the DEP South Texas NGL Pipeline System.

§ The *BRF* facility processes mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 75%, 74% and 70% during the years ended December 31, 2006, 2005 and 2004, respectively. These rates reflect the periods in which we owned an interest in such facilities. We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50% interest in a facility owned by Promix and a 32.2% interest in a facility owned by Baton Rouge Fractionators LLC (BRF).

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 currently loads cargoes of refrigerated propane and butane onto tanker vessels at rates of up to 5,000 barrels per hour. We are in the process of expanding our import and export facility. 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 127 MBPD, 119 MBPD and 91 MBPD for 2006, 2005 and 2004, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 18,889 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. 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, Permian, Piceance and Greater Green River 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 or municipal customers or to other onshore pipelines.

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 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 Texas, 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, Permian Basin and Jonah 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. On a combined basis, these facilities (our Petal Gas Storage (Petal) and Hattiesburg Gas Storage (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. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, including 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) monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer s usage, and (ii) storage fees per unit of volume stored at our facilities.

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 economically 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.

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Properties. The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 5, 2007.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approximate Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100%	8,140	5,155	
Jonah Gathering System	Wyoming	14.4% (1)	643	1,750	
Piceance Creek Gathering System	Colorado	100%	48	1,600	
San Juan Gathering System	New Mexico, Colorado	100%	6,065	1,200	
Acadian Gas System	Louisiana	Various (2)	1,042	954	
Permian Basin System	Texas, New Mexico	100%	1,387	490	
Alabama Intrastate System	Alabama	100%	408	200	
Encinal Gathering System	Texas	100%	452	143	
Other (5 systems) (3)	Texas, Mississippi	Various (4)	704		
Total miles			18,889		
Natural gas storage facilities:					
Petal	Mississippi	100%			11.9
Hattiesburg	Mississippi	100%			4.0
Wilson	Texas	Leased (5)			6.4
Acadian	Louisiana	Leased (6)			3.0
Total gross capacity					25.3

(1) Ownership interest as of December 31, 2006. This amount is expected to increase to approximately 20% upon completion of the Phase V expansion project.

(2) Reflects consolidated ownership of Acadian Gas by

the Operating Partnership (34%) and Duncan Energy Partners (66%). Also includes the 49.5% equity investment that Acadian Gas has in the Evangeline pipeline.

(3) Includes the Delmita, Big Thicket, Indian Springs and Canales 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. We acquired the Canales gathering system in connection with the Encinal acquisition in

July 2006.

(4) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% equity interest through a consolidated subsidiary.

(5) This facility is held under an operating lease that expires in January 2028.

(6) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 71%, 73% and 75% during the years ended December 31, 2006, 2005 and 2004, respectively. These rates reflect the periods in which we owned an interest in such assets.

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 and municipal 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, the Houston area, and the Houston Ship Channel industrial market. The Texas Intrastate System is comprised of the 7,292-mile Enterprise Texas Intrastate pipeline system, the 197-mile TPC Offshore gathering system and the 651-mile Channel pipeline system. The leased Wilson natural gas storage facility is an integral part of the Texas Intrastate System. We own 100% of the Texas Intrastate System with the exception of the Channel pipeline system, in which we own a 50% undivided interest.

§ The *Jonah Gathering System* is located in the Greater Green River Basin of southwestern Wyoming. This system gathers natural gas from the Jonah and Pinedale fields for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate pipelines. In August 2006, we entered into a joint venture with TEPPCO and are proceeding with an expansion of the Jonah Gathering System. For additional information regarding this joint venture arrangement with TEPPCO and related expansion project, see Item 13 of this annual report.

§ The *Piceance Creek Gathering System* consists of a recently constructed natural gas gathering pipeline located in the Piceance Basin of northwestern Colorado. This pipeline is owned by Piceance Creek Pipeline, LLC, the ownership interests of which we acquired from EnCana Oil & Gas (EnCana) in December 2006. The Piceance Creek Gathering System extends from a connection with EnCana s Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.7 Bcf/d Meeker natural gas treating and processing complex, which is currently under construction. Connectivity to EnCana s Great Divide Gathering System will provide the Piceance Creek Gathering System with access to natural gas production from the southern portion of the Piceance basin, including production from EnCana s Mamm Creek field. The Piceance Creek Gathering System was placed in service in January 2007 and began transporting initial volumes of approximately 300 MMcf/d of natural gas.

§ 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 10,400 wells in the San Juan Basin and delivers the natural gas to natural gas processing facilities, including our Chaco facility.

§ 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, 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The leased Acadian natural gas storage facility is an integral part of the Acadian Gas System.

We contributed a direct 66% equity interest in Acadian Gas, which is a subsidiary that owns the Cypress and Acadian pipelines, to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct interest in Acadian Gas. For additional information regarding this subsequent event, see *Recent Developments* within this Item 1. Acadian Gas owns a 49.5% indirect interest in the Evangeline pipeline.

§ 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 452-mile Waha system and 935-mile Carlsbad system.

§ The *Alabama Intrastate System* mainly 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.

§ The *Encinal Gathering System* gathers natural gas from the Olmos and Wilcox formations and delivers into our Texas Intrastate System, which delivers the natural gas into our south Texas facilities for processing. We acquired this gathering system in connection with the Encinal acquisition in July 2006.

§ 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

Our Offshore Pipelines & Services business segment includes (i) approximately 1,586 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 863 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

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 that are 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 transportation 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 (i) production from reserves committed under long-term contracts for the productive life of the relevant field or (ii) 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 six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities. 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 payments and commodity charges. Demand fees represent charges 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 payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers.

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.

Properties. The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 5, 2007, all of which are located in the Gulf of Mexico primarily offshore Louisiana and Texas.

				Approximate Net Capacity	
Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Natural Gas (MMcf/d)	Crude Oil (MPBD)
Offshore natural gas pipelines:					
VESCO Gathering System	13.1%	260		800	
Manta Ray Offshore Gathering System	25.7%	250		206	
High Island Offshore System	100%	204		1,800	
Viosca Knoll Gathering System	100%	164		1,000	
Green Canyon Laterals	Various (1)	136		649	
Anaconda Gathering System (2)	100%	136		550	
Independence Trail (3)	100%	134		1,000	
Nautilus System	25.7%	101		154	
East Breaks System	100%	85		400	
Phoenix Gathering System	100%	78		450	
Nemo Gathering System	33.9%	24		102	
Falcon Natural Gas Pipeline	100%	14		400	
Total miles		1,586			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline	50%	373			250
Poseidon Oil Pipeline System	36%	322			144
Constitution Oil Pipeline	100%	67			80
Allegheny Oil Pipeline	100%	43			140
Marco Polo Oil Pipeline	100%	37			120
Typhoon Oil Pipeline	100%	17			80
Tarantula Oil Pipeline	100%	4			30
Total miles		863			
Offshore platforms:					
Independence Hub(3)	80%		8,000	1,000	NA
Marco Polo	50%		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) Our ownership interests in the

Green Canyon Laterals ranges from 2.7% to 100%.

(2) Data shown for the Anaconda Gathering System includes the 30-mile Constitution natural gas pipeline, which we constructed and placed in-service in 2006. The Constitution natural gas pipeline has a net capacity of approximately 200 MMcf/d.

(3) Construction of the Independence Trail pipeline and Independence Hub platform are substantially complete. The Independence Hub platform and Independence Trail pipeline are expected to begin operations during the second half of 2007.

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. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 26%, 30% and 32% during the years ended December 31, 2006, 2005 and 2004, respectively. These rates reflect the periods in which we owned an interest in such assets.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

§ The *VESCO Gathering System* is a 260-mile regulated natural gas pipeline system associated with the Venice natural gas processing plant in Louisiana. This pipeline is an integral part of the natural gas processing operations of VESCO. Our 13.1% interest in this system is held through our equity method investment in VESCO.

§ 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. Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C.

§ 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 HIOS pipeline system includes 10 pipeline junction and service platforms.

§ 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 the third-party owned Constitution platform to the ANR pipeline system. The Anaconda Gathering System includes our wholly-owned Typhoon, Marco Polo and Constitution natural gas pipelines. The Constitution natural gas pipeline 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 natural gas pipeline during the first quarter of 2006.

§ The *Independence Trail* natural gas pipeline will transport natural gas from our Independence Hub platform to the Tennessee Gas Pipeline. Natural gas transported on the Independence Trail will come from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. This pipeline includes one pipeline junction platform at West Delta 68. We completed construction of the Independence Trail natural gas pipeline during 2006, with an expected in-service date during the second half of 2007.

§ The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant on the Louisiana gulf coast. Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C.

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

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

§ The *Falcon Natural 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. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 18%, 17% and 27% during the years ended December 31, 2006, 2005 and 2004, respectively. These rates reflect the periods in which we owned an interest in such assets.

§ 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. This pipeline includes one pipeline junction platform. Our 50% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company (Cameron Highway).

§ 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. This system includes one pipeline junction platform. Our ownership interest in this pipeline is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC.

§ 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* transports 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. Anadarko will operate the Independence Hub platform once it becomes operational.

On a weighted-average basis, utilization rates with respect to natural gas processing capacity of our offshore platforms were approximately 17%, 27% and 33% during the years ended December 31, 2006, 2005 and 2004, respectively. Likewise, utilization rates for our offshore platforms were approximately 19%, 9% and 14%, respectively, in connection with platform crude oil processing capacity. These rates reflect the periods in which we owned an interest in such assets. In addition to the offshore platforms we identified in the preceding table, we own or have an ownership interest in fifteen pipeline junction and service platforms. Our pipeline junction and service platforms do not have any processing capacity.

§ The *Independence Hub* platform is located in Mississippi Canyon Block 920. This platform will process crude oil and natural gas gathered from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. We expect to complete construction of the Independence Hub platform in March 2007, with an expected in-service date during the second half of 2007.

§ 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 fields and should begin processing production from the Genghis Khan field in the second quarter of 2007. These fields are located in the South

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Green Canyon area of the Gulf of Mexico. Our 50% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway LLC.

§ 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* platform currently processes natural gas from the Falcon field.

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 679 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 609 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, we sell our petrochemical products at market-related prices, which may 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.

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Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. Isobutane is used in the production of alkylate for motor gasoline, propylene oxide, isooctane and methyl tertiary butyl ether (MTBE). 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 isooctane, which is an additive used in reformulated motor gasoline blends to increase octane, and isobutylene. The facility produces isooctane and isobutylene using feedstocks of high-purity isobutane, which is supplied using production from our isomerization units.

Prior to mid-2005, the facility produced MTBE. 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 eliminated the requirement of oxygenates in reformulated motor gasoline. As a result of such developments, we modified the facility to produce isooctane and isobutylene. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

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 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 and petrochemical companies 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

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Properties. The following table summarizes the significant assets of our Petrochemical Services segment at February 5, 2007, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (3 plants)	Texas	Various (1)	58	72	
BRPC	Louisiana	30% (2)	7	23	
Total capacity			65	95	
Isomerization facility:					
Mont Belvieu (3)	Texas	100%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100%(4)			284
Texas City RGP Gathering System	Texas	100%			108
Lake Charles	Texas, Louisiana	50%			83
Others (6 systems)(5)	Texas, Louisiana	Various (6)			204
Total miles					679
Octane additive production facilities:					
Mont Belvieu	Texas	100%	12	12	

(1) 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.

(2) Our ownership interest in this facility is held indirectly through

our equity method investment in Baton Rouge Propylene Concentrator LLC (BRPC).

(3) On a weighted-average basis, utilization rates for this facility were approximately 70% during each of 2006 and 2005 and 66% during 2004.

(4) Reflects consolidated ownership of these pipelines by the Operating Partnership (34%) and Duncan Energy Partners (66%).

(5) Includes our Texas City PGP Gathering System and Port Neches, Bay Area, La Porte, Port Arthur and Bayport petrochemical pipelines.

(6) We own 100% of these pipelines with the exception of 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
Pipeline GP,
L.L.C.

We produce polymer grade propylene at our Mont Belvieu location 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. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 86%, 83% and 86% during the years ended December 31, 2006, 2005 and 2004, respectively. 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.

The Lou-Tex propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana. We own these pipelines through our subsidiaries, Lou-Tex Propylene and Sabine Propylene.

On February 5, 2007, we contributed a direct 66% equity interest in our subsidiaries that own the Lou-Tex Propylene and Sabine Propylene pipelines to Duncan Energy Partners. We own the remaining 34% direct interest in these subsidiaries. For additional information regarding this subsequent event, see *Recent Developments* within this Item 1.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 97 MBPD, 64 MBPD and 71 MBPD during the years ended December 31, 2006, 2005 and 2004, respectively.

Our octane additive facility currently has an isooctane production capacity of 12.0 MBPD. The facility was capable of producing only MTBE prior to mid-2005 at a rate up to 15.5 MBPD. On a weighted-average combined product basis, utilization rates for this facility were approximately 45%, 29% and 83% during the years ended December 31, 2006, 2005 and 2004, respectively.

Title to Properties

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.

Capital Spending

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures with industry partners. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from such areas as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, Barnett Shale in North Texas, and the deepwater Gulf of Mexico. For a discussion of our capital spending program, see *Capital Spending* included under Item 7 of this annual report.

Regulation

Interstate Regulation

Liquids Pipelines. Certain of our crude oil and NGL pipeline systems (collectively referred to as liquids pipelines) are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act (ICA) and the Energy Policy Act of 1992 (Energy Policy Act). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to investigate such rates and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deemed liquids pipeline rates that were in effect for the twelve months preceding enactment and that had not been subject to complaint, protest or investigation, just and reasonable under the Energy Policy Act (i.e., grandfathered). Some, but not all, our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year-to-year in the Producer Price Index for finished goods (PPI). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline s costs. Effective March 21, 2006, FERC concluded that for the five-year period commencing July 1, 2006, liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 1.3%.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings (Market-Based Rates) or agreements with all of the pipeline s shippers that the rate is acceptable.

Because of the complexity of ratemaking, the lawfulness of any rate is never assured. The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC s approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow. Challenges to our tariff rates could be filed with the FERC. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

The Lou-Tex Propylene pipeline is an interstate common carrier pipeline regulated under the ICA by the Surface Transportation Board (STB), a part of the United States Department of Transportation. If the STB finds that a carrier s rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier s revenue needs and the availability of other economic transportation alternatives.

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

Natural Gas Pipelines. Our interstate natural gas pipelines and storage facilities are regulated by the FERC under the Natural Gas Act of 1938 (NGA). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered by the FERC, on its own initiative, or as a result of challenges to the rates by third parties if they are found unlawful and the FERC could require refunds of amounts collected under such unlawful rates. Our rates are derived based on a cost-of-service methodology.

One element of the FERC s cost-of-service methodology as it affects partnerships such as ours is an income tax allowance. Pursuant to an order on remand of a decision by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast, LLC v. FERC* and a policy statement regarding income tax allowance issued by the FERC, the FERC will permit a pipeline to include in cost-of-service a tax allowance to reflect actual or potential tax liability on its public utility income attributable to all partnership or limited liability company interests if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case by case basis. Both the FERC s income tax allowance policy and its initial application in an individual pipeline proceeding are being challenged in the court of appeals.

The FERC s authority over companies that provide natural gas pipeline transportation or storage services also includes (i) certification, construction, and operation of new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and discontinuation of covered services; and (v) various other matters. In addition, pursuant to the Energy Policy Act of 2005, the NGA and the Natural Gas Policy Act of 1978 (NGPA) were amended to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1 million per day per violation.

Offshore Pipelines. Our offshore pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act (OCSLA), which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Regulation

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Certain of our intrastate pipelines are subject to regulation by the FERC under the NGPA and provide transportation and storage service pursuant to Section 311 of the NGPA and the FERC s regulations. Under Section 311 of the NGPA, an intrastate pipeline company may transport gas for an interstate pipeline or any local distribution company served by an interstate pipeline. We are required to provide these services on an open and nondiscriminatory basis. The rates for 311 service may be established by the FERC or the respective state agency, but may not exceed a fair and equitable rate.

Certain other of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may also challenge our intrastate tariff rates and practices on our pipelines.

Environmental and Safety Matters

General

Our operations are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Clean Air Act; the Federal Water Pollution Control Act or the Clean Water Act; the Oil Pollution Act; and analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at a facility that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, other than certain matters discussed under Item 3 of this annual report, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations or cash flows. Environmental and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating

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restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990 (OPA), which addresses three principal areas of oil pollution prevention, containment and cleanup, and liability. OPA subjects owners of certain facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. Any unpermitted release of petroleum or other pollutants from our operations could also result in fines or penalties. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety (OPS) or the EPA, as appropriate.

Some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Contamination resulting from spills or releases of petroleum products is an inherent risk within our industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems as a result of past operation, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, but such costs are site specific and we cannot predict that the effect will not be material in the aggregate.

Air Emissions

Our operations are subject to the Federal Clean Air Act (the Clean Air Act) and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our permits and related compliance obligations under the Clean Air Act, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur capital expenditures to add to or modify existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the Clean Air Act and many state laws. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Congress is currently considering proposed legislation directed at reducing greenhouse gas emissions. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes, including hazardous substances, that are subject to the requirements of the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws, which impose detailed requirements for the handling, storage treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the waste meets certain treatment standards or the land-disposal method meets certain waste containment criteria.

Environmental Remediation

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as Superfund, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a facility where a release occurred, transporters that select the site of disposal of hazardous substances and companies that disposed of or arranged for the disposal of any hazardous substances found at a facility. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our operations, our pipeline systems generate wastes that may fall within CERCLA s definition of a hazardous substance. In the event a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

Pipeline Safety Matters

We are subject to regulation by the United States Department of Transportation (DOT) under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act (HLPSA), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products. The HLPSA requires any entity that owns or operates pipeline facilities to (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Secretary of Transportation. We believe that we are in material compliance with these HLPSA regulations.

We are subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. We believe that we are in material compliance with these DOT regulations.

We are also subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas (HCAs). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program (IMP) that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In compliance with these DOT regulations, we identified our HCA pipeline segments and have developed an IMP. We believe that the established IMP meets the requirements of these DOT regulations.

Risk Management Plans

We are subject to the EPA s Risk Management Plan (RMP) regulations at certain facilities. These regulations are intended to work with the Occupational Safety and Health Act (OSHA) Process Safety Management regulations (see Safety Matters below) to minimize the offsite consequences of catastrophic releases. The regulations required us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with our risk management program.

Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

We are subject to OSHA Process Safety Management (PSM) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request.

Employees

As of December 31, 2006, approximately 1,900 persons spend 100% of their time engaged in the management and operations of our business, and 100% of the cost for their services is reimbursed to EPCO under an administrative services agreement, except for approximately 80 persons employed and paid directly by Dixie. In addition approximately 1,100 persons assigned to EPCO s shared service organizations spend all or a portion of their time engaged in our business. The cost for their services is reimbursed to EPCO under an administrative services agreement (see Item 13) and is generally based on the percentage of time such employees perform services on our behalf during the year. All of the foregoing persons, except the approximately 80 who are employed directly by Dixie, are employees of EPCO. In addition to the EPCO employees, there are approximately 150 contract maintenance and other various contract personnel engaged in our business. For additional information regarding our relationship with EPCO, see Item 13 of this annual report.

Available Information

As a large accelerated filer, we electronically file certain documents with the U.S. Securities and Exchange Commission (SEC). We file 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

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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.epplp.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) 381-6521 for paper copies of these reports free of charge.

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

An investment in our common 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 common units could decline, and you could lose part or all of your investment.

The following section lists some, but not all, of the key risk factors that may have a direct impact on our business, results of operations, cash flows and financial condition. The items are not listed in terms of importance or level of risk.

Risks Relating to Our Business

Changes in demand for and production of hydrocarbon products may materially adversely affect our results of operations, cash flows and financial condition.

We operate predominantly in the midstream energy sector 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 materially adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. Changes in prices and changes in the relative price levels may impact demand for hydrocarbon products, which in turn may impact production and volumes of product for which we provide services. We may also incur price risk to the extent counterparties do not perform in connection with our marketing of natural gas, NGLs and propylene.

In the past, the prices of natural gas have been extremely volatile, and we expect this volatility to continue. The NYMEX daily settlement price for natural gas for the prompt month contract in 2004 ranged from a high of $8.75 per MMBtu to a low of $4.57 per MMBtu. In 2005, the same index ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu. In 2006, the same index ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu.

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. Some of 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;

- the impact of conservation efforts;
- the extent of governmental regulation and taxation of production; and
- the overall economic environment.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our 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 our results of operations, cash flows and financial position.

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

Our profitability could be materially 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.

The crude oil, natural gas and NGLs available to our facilities will be derived from reserves produced from existing wells, which reserves naturally decline over time. To offset this natural decline, our facilities will need access to additional reserves. Additionally, some of our 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 our 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 our facilities are located. This could result in a decrease in volumes to our offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on our 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 our 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 our results of operations, cash flows and financial position. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), 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 as an ethylene feedstock.

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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 we transport.

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, our operating margin from selling isobutane could be reduced.

Propylene. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we transport.

We face competition from third parties in our midstream businesses.

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

§ geographic proximity to the production;

§ costs of connection;

§ available capacity;

§ rates; and

§ access to markets.

Our future debt level may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of December 31, 2006, we had approximately $5.3 billion of consolidated debt outstanding. In addition, as of February 5, 2007, Duncan Energy Partners had approximately $200.0 million outstanding under its credit facility. The amount of our future debt could have significant effects on our operations, including, among other things:

§ a substantial portion of our cash flow, including that of Duncan Energy Partners, could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

§ credit rating agencies may view our debt level negatively;

§ covenants contained in our existing and future credit and debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

§ our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

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

§ we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

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

Our Multi-Year Revolving Credit Facility and each of our indentures for our public debt contain conventional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under our Multi-Year Revolving Credit Facility. A breach of any of these restrictions by us could permit our 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 our Multi-Year Revolving Credit Facility, to terminate all commitments to extend further credit. For additional information regarding our Multi-Year Revolving Credit Facility, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty assessing capital markets or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term securities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we 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 our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our 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 our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand alone projects or other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

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

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

Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses (either for ourselves or direct Duncan Energy Partners to do so) that we believe complement our existing operations. We may be unable to integrate successfully businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our results of operations, cash flows and financial condition. Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

§ 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 we are required to maintain under the Sarbanes-Oxley Act of 2002;

§ managing relationships with new joint venture partners with whom we have 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, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our 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.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Even if we make acquisitions that we believe will be accretive, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves potential risks, including, among other things:

§ mistaken assumptions about volumes, revenues and costs, including synergies;

§ an inability to integrate successfully the businesses we acquire;

§ decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;

- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management s and employees attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our operating cash flows from our capital projects may not be immediate.

We are engaged in several construction projects involving existing and new facilities for which significant capital has been or will be expended, and our operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if we build 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 we 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 we experience any unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

Our actual construction, development and acquisition costs could exceed forecasted amounts.

We have significant expenditures for the development and construction of energy infrastructure assets, including construction and development projects with significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project s initiation or that we currently estimate. For example, material and labor cost trends associated with our projects in the Rocky Mountains region have increased since the initiation of these projects due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Katrina and Rita during 2005.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

- we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

- § we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;
- § we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;
- § since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third-party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;
- § where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves; and
- § we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects.

One of the connections between our DEP South Texas NGL Pipeline System and the Mont Belvieu facility is a pipeline we have leased from TEPPCO. The initial term of this lease will expire on September 15, 2007, and if we are unable to construct our planned replacement pipeline or extend the lease, the operations of our DEP South Texas NGL Pipeline System will be interrupted. We cannot assure you that any construction will not be delayed due to government permits, weather conditions or other factors beyond our control.

We may not be able to consummate future public offerings of Duncan Energy Partners on terms that we expect or at all, which would result in less cash available for us to fund our capital spending program.

Duncan Energy Partners was formed in part to acquire, own and operate midstream energy businesses of ours. In the future, we may contribute additional equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. Although Duncan Energy Partners successfully completed its initial public offering in February 2007, there is no guarantee that Duncan Energy Partners will be able to complete future offerings of its securities in amounts that we would expect. If this occurs, we would have less cash available to fund our capital spending program, which could result in less cash distributions.

Substantially all of the common units in us that are owned by EPCO and its affiliates are pledged as security under EPCO s credit facility. Additionally, all of the member interests in our general partner and all of the common units in us that are owned by Enterprise GP Holdings are pledged under its credit facility. Upon an event of default under either of these credit facilities, a change in ownership or control of us could ultimately result.

An affiliate of EPCO has pledged substantially all of its common units in us as security under its credit facility. EPCO s credit facility contains customary and other events of default relating to defaults of EPCO and certain of its subsidiaries, including certain defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on EPCO s pledged collateral, could ultimately result in a change in ownership of us. In addition, the 100% membership interest in our general partner and the 13,454,498 of our common units that are owned by Enterprise GP Holdings are pledged under Enterprise GP Holdings credit facility. Enterprise GP Holdings credit facility contains customary and other events of default. Upon an event of default, the lenders under Enterprise GP Holdings credit facility could foreclose on Enterprise GP Holdings assets, which could ultimately result in a change in control of our general partner and a change in the ownership of our units held by Enterprise GP Holdings.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner or owners of a general partner may be factors in credit evaluations of a limited partnership. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Entities controlling the owner of our general partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their general partner and limited partner equity interests in us, Enterprise GP Holdings and TEPPCO to service such indebtedness. Any distributions by us, Enterprise GP Holdings and TEPPCO to such entities will be made only after satisfying our then current obligations to creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of Dan L. Duncan or the entities that control our general partner were viewed as substantially lower or more risky than ours.

The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a partnership holding company with no business operations and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners. The ability of our subsidiaries and joint ventures to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies. For example, all cash flows from Evangeline are currently used to service its debt.

In addition, the charter documents governing our joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which we participate 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 us under certain circumstances. Accordingly, our joint ventures may be unable to make distributions to us at current levels if at all.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has 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, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us 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 us 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 our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane risk.

If one or more facilities that are owned by us or that deliver oil, natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our 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 we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers natural gas is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on behalf of us, although insurance will not cover many types of interruptions that might occur and will not cover amounts up to applicable deductibles. 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. For example, change in the insurance markets subsequent to the terrorist attacks on September 11, 2001 and the hurricanes in 2005 have made it more difficult for us to obtain certain types 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. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our 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.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2006, our balance sheet reflected $590.5 million of goodwill and $1.0 billion 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. Accounting principles generally accepted in the United States (GAAP) require us 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 we determine that any of our goodwill or intangible assets were impaired, we 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 our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of December 31, 2006, we had approximately $5.3 billion of consolidated debt, of which approximately $3.8 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, we may enter into additional interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, our 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 our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

The use of derivative financial instruments could result in material financial losses by us.

We historically have 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 we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our 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.

Our pipeline integrity program may impose significant costs and liabilities on us.

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, we 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. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Environmental costs and liabilities and changing environmental regulation could materially affect our results of operations, cash flows and financial condition.

Our 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. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We 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 our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Federal, state or local regulatory measures could materially adversely affect our business, results of operations, cash flows and financial condition.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the Natural Gas Act, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our 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 our services are provided on a non- discriminatory basis so that all shippers have open access to our 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.

We have 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.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the Natural Gas Policy Act. We also have 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 our assets, see Item 1 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to you.

The workplaces associated with our facilities are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to you.

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Terrorist attacks aimed at our facilities could adversely affect our 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 our facilities or pipelines or those of our customers could have a material adverse effect on our business.

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

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the chairman of our general partner. Mr. Duncan has been integral to our success and the success of 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 key members of our senior management team could have a material adverse effect on our business, results of operations, cash flows, market price of our securities and financial condition.

EPCO s employees may be subjected to conflicts in managing our business and the allocation of time and compensation costs between our business and the business of EPCO and its other affiliates.

We have no officers or employees and rely solely on officers of our general partner and employees of EPCO. Certain of our officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders best interests. In addition, these overlapping officers allocate their time among us, EPCO and other affiliates of EPCO. These officers face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into an administrative services agreement that governs business opportunities among entities controlled by EPCO, which includes us and our general, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner and TEPPCO and its general partner. For information regarding how business opportunities are handled within the EPCO group of companies, please read Item 13 of this annual report.

We do not have an independent compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

Subject to NYSE rules, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

§ the proportionate ownership interest of a common unit will decrease;

§ the amount of cash available for distributions on each common unit may decrease;

§ the ratio of taxable income to distributions may increase;

§ the relative voting strength of each previously outstanding common unit may be diminished; and

§ the market price of our common units may decline.

We may not have sufficient cash from operations to pay distributions at the current level following establishment of cash reserves and payments of fees and expenses, including payments to Enterprise Products GP.

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of Enterprise Products GP. These factors include but are not limited to the following:

§ the level of our operating costs;

§ the level of competition in our business segments;

§ prevailing economic conditions;

§ the level of capital expenditures we make;

§ the restrictions contained in our debt agreements and our debt service requirements;

§ fluctuations in our working capital needs;

§ the cost of acquisitions, if any; and

§ the amount, if any, of cash reserves established by Enterprise Products GP in its sole discretion.

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

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements and fees due to EPCO and its affiliates, including our general partner may be substantial and will reduce our cash available for distribution to holders of our units.

Prior to making any distribution on our units, we will reimburse EPCO and its affiliates, including officers and directors of Enterprise Products GP, for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to pay cash distributions to holders of our

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units. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

Enterprise Products GP and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of Enterprise Products GP and its affiliates have duties to manage Enterprise Products GP in a manner that is beneficial to its members. At the same time, Enterprise Products GP has duties to manage our partnership in a manner that is beneficial to us. Therefore, Enterprise Products GP s duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

§ neither our partnership agreement nor any other agreement requires Enterprise Products GP or EPCO to pursue a business strategy that favors us;

§ decisions of Enterprise Products GP regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and Enterprise Products GP;

§ under our partnership agreement, Enterprise Products GP determines which costs incurred by it and its affiliates are reimbursable by us;

§ Enterprise Products GP is allowed to resolve any conflicts of interest involving us and Enterprise Products GP and its affiliates;

§ Enterprise Products GP is allowed to take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;

§ any resolution of a conflict of interest by Enterprise Products GP not made in bad faith and that is fair and reasonable to us shall be binding on the partners and shall not be a breach of our partnership agreement;

§ affiliates of Enterprise Products GP, including TEPPCO, may compete with us in certain circumstances;

§ Enterprise Products GP has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

§ we do not have any employees and we rely solely on employees of EPCO and its affiliates;

§ in some instances, Enterprise Products GP may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions;

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

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§ Enterprise Products GP intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

§ Enterprise Products GP controls the enforcement of obligations owed to us by our general partner and its affiliates; and

§ Enterprise Products GP decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by Dan L. Duncan, including EPCO and TEPPCO. For detailed information on these relationships and related transactions with these entities, see Item 13 included within this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders did not elect Enterprise Products GP or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove Enterprise Products GP or its officers or directors. Enterprise Products GP may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Because affiliates of Enterprise Products GP currently own approximately 33.9% of our outstanding common units, the removal of Enterprise Products GP as our general partner is not practicable without the consent of both Enterprise Products GP and its affiliates.

Unitholders voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of 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 of these provisions, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

Enterprise Products GP has a limited call right that may require common unitholders to sell their units at an undesirable time or price.

If at any time Enterprise Products GP and its affiliates own 85% or more of the common units then outstanding, Enterprise Products GP 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 remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon a sale of their units.

Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business.

Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

§ we were conducting business in a state, but had not complied with that particular state s partnership statute; or

§ your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted control of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the Delaware Act), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

A large number of our outstanding common units may be sold in the market, which may depress the market price of our common units.

Shell owned 26,976,249 of our common units, representing approximately 6.2% of our outstanding common units at December 31, 2006, and has publicly announced its intention to reduce its holdings of our common units on an orderly schedule over a period of years, taking into account market conditions. All of the common units held by Shell are registered for resale under our effective registration statement on Form S-3. Shell sold 2,431,300 of our common units to third parties during the year ended December 31, 2006. In addition, Shell sold approximately 7,340,500 of our common units during January 2007.

Affiliates of Lewis Energy Group L.P. (collectively, Lewis) owned 7,070,644 of our common units, representing approximately 1.6% of our outstanding common units at December 31, 2006, and have publicly announced their intention to reduce their holdings of our common units on an orderly schedule, taking into account market conditions. All of the common units held by Lewis are registered for resale under our effective registration statement on Form S-3. Lewis sold 45,200 of our common units to third parties during the year ended December 31, 2006.

Sales of a substantial number of our common units in the public market could cause the market price of our common units to decline. As of February 1, 2007, we had 432,408,430 common units outstanding. Sales of a substantial number of these common units in the trading markets, whether in a single transaction or series of transactions, or the possibility that these sales may occur, could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service (IRS) on this matter.

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%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow though to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states (including Texas) are evaluating ways to enhance state-tax collections. For example, our operating subsidiaries will be subject to a newly revised Texas franchise tax (the Texas Margin Tax) on the portion of their revenue that is generated in Texas beginning for tax reports due on or after January 1, 2008. Specifically, the Texas Margin Tax will be imposed at a maximum effective rate of 0.7% of the operating subsidiaries gross revenue that is apportioned to Texas. If any additional state were to impose a entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our common unitholders would be reduced.

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

The IRS may adopt positions that differ from the positions 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 the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

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

Common 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 even if they do not receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from their share of our taxable income.

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

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

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

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

We will treat each purchaser of our common 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 common units.

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

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Our common 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, they may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of the common unitholder to file all United States federal, state and local tax returns.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

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

Item 1B. *Unresolved Staff Comments*.

None.

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Item 3. *Legal Proceedings*.

On occasion, we are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we insure 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 activities. We are not aware of any significant litigation, pending or threatened, that we believe may individually have a significant adverse effect on our financial position, cash flows or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against various manufacturers of reformulated gasoline containing methyl tertiary butyl ether (MTBE). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

We acquired additional ownership interests in our octane-additive production facility from affiliates of Devon Energy Corporation (Devon), which sold us its 33.3% interest in 2003, and Sunoco, Inc. (Sun), which sold us its 33.3% interest in 2004. As a result of these acquisitions, we own 100% of our Mont Belvieu, Texas octane-additive production facility. Devon and Sun have indemnified us for any liabilities (including potential liabilities as described in the preceding paragraph) 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 our octane-additive production facility.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO, and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. The complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates, including the parent company of our general partner; (iii) EPCO, Inc.; and (iv) Dan L. Duncan. The complaint alleges, among other things, that the defendants have caused TEPPCO to enter into certain transactions with us or our affiliates that are unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include the joint venture to further expand the Jonah Gathering System entered into by TEPPCO and one of our affiliates in August 2006 and the sale by TEPPCO to one of our affiliates of the Pioneer gas processing plant in March 2006. The complaint seeks (i) rescission of these transactions or an award of rescissory damages with respect thereto; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. For information regarding our relationship with TEPPCO, see Item 13 of this annual report.

On February 13, 2007, our Operating Partnership received notice from the U.S. Department of Justice (DOJ) that it was the subject of a criminal investigation related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (Magellan). Our Operating Partnership is the operator of this pipeline. On February 14, 2007, our Operating Partnership received a letter from the Environment and Natural Resources Division (ENRD) of the DOJ regarding this incident and a previous release of ammonia on September 27, 2004 from the same pipeline. The ENRD has indicated that it may pursue civil damages against our Operating Partnership and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against our Operating Partnership and Magellan is up to $17.4 million in the aggregate. Our Operating Partnership is cooperating with the DOJ and is hopeful that an expeditious resolution acceptable to all parties will be reached in the near future. Our Operating Partnership is seeking defense and indemnity under the pipeline operating agreement between it and Magellan. At this time, we do not believe that a final resolution of either the criminal investigation by the DOJ or the civil claims by the ENRD will have a material impact on our consolidated results of operations.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. We and Magellan are in the process of estimating the repair and remediation costs associated with this release. Environmental remediation efforts continue in and around the site of the release under the supervision and management of affiliates of Magellan. Our operating agreement with Magellan provides the Operating Partnership with an indemnity clause for claims arising from such releases. At this time, we do not believe that this incident will have a material impact on our consolidated results of operations.

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

None.

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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 common units are listed on the NYSE under the ticker symbol EPD. As of February 1, 2007, there were an approximately 930 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2005					
1st Quarter	$28.350	$23.920	$0.4100	Apr. 29, 2005	May 10, 2005
2nd Quarter	$27.090	$24.770	$0.4200	Jul. 29, 2005	Aug. 10, 2005
3rd Quarter	$27.660	$23.500	$0.4300	Oct. 31, 2005	Nov. 8, 2005
4th Quarter	$26.020	$23.380	$0.4375	Jan. 31, 2006	Feb. 9, 2006
2006					
1st Quarter	$26.000	$23.690	$0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter	$25.710	$23.760	$0.4525	Jul. 31, 2006	Aug. 10, 2006
3rd Quarter	$27.060	$25.000	$0.4600	Oct. 31, 2006	Nov. 8, 2006
4th Quarter	$29.980	$26.050	$0.4675	Jan. 31, 2007	Feb. 8, 2007

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 partners) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to partners primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see *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 during 2006.

Common Units Authorized for Issuance Under Equity Compensation Plan

See 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 common units during 2006. In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). As of February 15, 2007, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

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

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from our audited financial statements and should be read in conjunction with the audited financial statements included under Item 8 of this annual report. 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 are in thousands (except per unit data).

	For the Year Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Operating results data: (1)					
Revenues	$13,990,969	$12,256,959	$8,321,202	$5,346,431	$3,584,783
Income from continuing operations (2)	$ 599,683	$ 423,716	$ 257,480	$ 104,546	$ 95,500
Income per unit from continuing operations:					
Basic	$ 1.22	$ 0.92	$ 0.83	$ 0.42	$ 0.55
Diluted	$ 1.22	$ 0.92	$ 0.83	$ 0.41	$ 0.48
Other financial data:					
Distributions per common unit(3)	$ 1.825	$ 1.698	$ 1.540	$ 1.470	$ 1.360
Commodity hedging income (loss) (4)	$ 10,257	$ 1,095	$ 448	$ (619)	$ (51,344)

	As of December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Financial position data: (1)					
Total assets	$13,989,718	$12,591,016	$11,315,461	$4,802,814	$4,230,272
Long-term and current maturities of debt (5)	$ 5,295,590	$ 4,833,781	$ 4,281,236	$2,139,548	$2,246,463
Partners equity(6)	$ 6,480,233	$ 5,679,309	$ 5,328,785	$1,705,953	$1,200,904
Total units outstanding (excluding treasury) (6)	432,408	389,861	364,786	217,780	183,810

(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. We accounted for the GulfTerra Merger and our other acquisitions using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective acquisition dates. For additional information regarding such transactions, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Amounts presented for the years ended December 31, 2006, 2005 and 2004 are before the cumulative effect of

accounting changes.

(3) Distributions per common unit represent declared cash distributions with respect to the four fiscal quarters of each period presented.

(4) 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, see Item 7A of this annual report.

(5) 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 other capital spending.

(6) We regularly issue common units through underwritten public offerings and, less frequently, in connection with acquisitions or other transactions. The increase in partners equity since 2002 has been the result of such transactions, with the September 2004 issuance of 104.5 million common units in connection with the GulfTerra Merger being our largest. For additional information regarding our partners equity

and unit history, 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, 2006, 2005 and 2004.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes listed in the Index to Consolidated Financial Statements on page F-1 of this annual report. Our discussion and analysis includes the following:

Overview of Business.

Results of Operations Discusses material year-to-year variances in our Consolidated Statements of Operations.

Liquidity and Capital Resources Addresses available sources of liquidity and analyzes cash flows.

Critical Accounting Policies Presents accounting policies that are among the most significant to the portrayal of our financial condition and results of operations.

Other Items Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and similar disclosures.

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, 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 operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner 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.

As generally used in the energy industry and in this discussion, 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 decatherms
MMBbls	=	million barrels
MMBtus	=	million British thermal units
MMcf	=	million cubic feet
Mcf	=	thousand cubic feet
TBtu	=	trillion British thermal units

Our financial statements have been prepared in accordance with accounting standards generally accepted in the United States of America (GAAP).

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Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids (NGLs), and crude oil, and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPD.

We conduct substantially all of our business through our Operating Partnership. We are owned 98% by our limited partners and 2% by our general partner, referred to as Enterprise Products GP. Enterprise Products GP is owned 100% by Enterprise GP Holdings, a publicly traded affiliate listed on the NYSE under the ticker symbol EPE. We, Enterprise Products GP and Enterprise GP Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and the controlling shareholder of EPCO.

Our midstream energy 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: 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 technologies employed) and products produced and/or sold.

Recent Developments

The following information highlights our significant developments since January 1, 2006 through the date of this filing. For additional information regarding the capital projects and acquisitions highlighted below, see *Capital Spending Significant Recently Announced Growth Capital Projects* included within this Item 7.

In February 2007, Duncan Energy Partners L.P. (Duncan Energy Partners), a consolidated subsidiary of ours, completed an underwritten initial public offering of 14,950,000 of its common units. We formed Duncan Energy Partners as a Delaware limited partnership to acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see *Other Items Initial Public Offering of Duncan Energy Partners* included within this Item 7.

In December 2006, we purchased all of the membership interests in Piceance Creek Pipeline, LLC (Piceance Creek Pipeline) from an affiliate of the EnCana Corporation (EnCana) for $100 million. The assets of Piceance Creek Pipeline consist primarily of a recently constructed 48-mile natural gas gathering pipeline (the Piceance Creek Gathering System) located in the Piceance Basin of northwest Colorado. This pipeline will connect to our Meeker natural gas processing plant, which is currently under construction.

In December 2006, Standard & Poor s raised its credit rating of our Operating Partnership from BB+ to BBB-, which is investment grade, with a stable outlook. As a result of this change, all of the senior unsecured credit ratings of our Operating Partnership are currently at an investment grade level.

In November 2006, we entered into a 30-year agreement with an affiliate of Exxon Mobil Corporation (ExxonMobil), to provide gathering, compression, treating and conditioning services for natural gas produced as part of a development program planned by ExxonMobil in the Piceance Basin in Colorado. Under the terms of the agreement, ExxonMobil s natural gas production from its Piceance Development Project, which encompasses more than 29,000 acres in Rio Blanco County, Colorado, will be dedicated to us. The fee-based agreement includes an option for us to recover NGLs beyond those extracted to condition the gas to meet downstream pipeline specifications.

To provide these services, we expect to invest approximately $185 million to construct new plant and pipeline facilities to compress the natural gas, treat it to remove impurities, extract NGLs, and deliver gas to the various pipeline transmission systems that serve the region. Construction of the facilities will begin after the receipt of the necessary permits and approvals and is expected to be completed in late 2008.

In November 2006, we announced an expansion of our Texas Intrastate Pipeline with the construction of a 178-mile pipeline (the Sherman Extension) that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. This new pipeline is expected to cost $424.6 million, most of which will be spent in 2008, and be placed in service during the fourth quarter of 2008.

In October 2006, we signed definitive agreements with producers to construct, own and operate an offshore oil pipeline that will provide firm gathering services from the Shenzi production field located in the Southern Green Canyon area of the central Gulf of Mexico.

In September 2006, we sold 12,650,000 of our common units in an underwritten public offering, which generated net proceeds of approximately $320.8 million.

During the third quarter of 2006, the Operating Partnership sold $550 million in principal amount of fixed/floating unsecured junior subordinated notes due 2066 (the Junior Subordinated Notes A). For additional information regarding this issuance of debt, see *Liquidity and Capital Resources Debt Obligations* included within this Item 7.

In August 2006, we became a joint venture partner with TEPPCO involving its Jonah Gas Gathering Company (Jonah). Jonah owns the Jonah Gathering System, located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants, including our Pioneer plant, and major interstate pipelines that deliver natural gas to end-use markets. As part of this new joint venture, we and TEPPCO are significantly expanding the Jonah Gathering System (the Phase V expansion project).

In August 2006, we purchased a 220-mile NGL pipeline extending from Corpus Christi, Texas to Pasadena, Texas from ExxonMobil Pipeline Company. The total purchase price for this asset was $97.7 million in cash. This pipeline (in combination with others to be constructed or acquired) will be used to transport NGLs from our South Texas natural gas processing plants to our Mont Belvieu fractionation facilities. Duncan Energy Partners acquired an indirect 66% interest in this pipeline asset on February 5, 2007.

In August 2006, our wholly owned subsidiary, Mid-America Pipeline Company LLC (Mid-America), executed new long-term transportation agreements with all but one of its current shippers on its Rocky Mountain pipeline pursuant to terms and conditions of Mid-America s open season tariff that was accepted by the Federal Energy Regulatory Commission effective August 6, 2006. Under the terms of the new agreements, shippers have committed to transport all of their current and future NGL production from the Rocky Mountains through the Mid-America Pipeline System to either our Hobbs fractionator (expected to be operational by mid-2007) or to Mont Belvieu, Texas via our Seminole Pipeline for a minimum of 10 years and up to a maximum of 20 years. Based on shipper production forecasts and current NGL extraction rates, we expect that these new agreements will fully utilize our Mid-America Pipeline System, including the 50 MBPD Phase I Expansion expected to be placed in-service during the third quarter of 2007.

In July 2006, we signed long-term agreements with CenterPoint Energy Resources Corp. (CenterPoint Energy) to provide firm natural gas transportation and storage services to its

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natural gas utility, primarily in the Houston, Texas metropolitan area. We will provide CenterPoint Energy with an estimated 14 Bcf per year of natural gas beginning in April 2007. Our deliveries to CenterPoint Energy through these new contracts will mark the first time that we have had the opportunity to serve the growing Houston area natural gas market. We are already the primary natural gas service provider to the San Antonio and Austin, Texas markets.

In July 2006, we acquired the Encinal and Canales natural gas gathering systems and their related gathering and processing contracts and other amounts that comprised the South Texas natural gas transportation and processing business of Cerrito Gathering Company, Ltd., an affiliate of Lewis Energy Group, L.P. (Lewis). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the Encinal acquisition) was $326.3 million, which includes $145.2 million in cash paid to Lewis and the issuance of 7,115,844 of our common units to Lewis.

In April 2006, we announced plans to expand our Houston Ship Channel NGL import and export facility and related pipeline and other assets to accommodate an expected increase in throughput volumes.

In March 2006, we purchased the Pioneer natural gas processing plant and certain related natural gas processing rights from TEPPCO for $38.2 million in cash.

In March 2006, we announced plans to expand our petrochemical assets located in southeast Texas. The plans include the construction of a new propylene fractionator at our Mont Belvieu, Texas facility and the expansion of two refinery grade propylene pipelines.

In March 2006, we sold 18,400,000 of our common units in a public offering, which generated net proceeds of approximately $430 million.

In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of EnCana. Under this agreement, we 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 began 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 processing facility to our Mid-America Pipeline System.

Capital Spending

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from such areas as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, Barnett Shale in North Texas, and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. 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.

Based on information currently available, we estimate our consolidated capital spending for 2007 will approximate $1.9 billion, which includes estimated expenditures of $1.7 billion for growth capital projects and acquisitions and $0.2 million for sustaining capital expenditures.

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Our forecast of consolidated capital expenditures is based on our strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management 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 a 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 the Year Ended December 31,		
	2006	**2005**	**2004**
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			$ 655,277
Transaction fees and other direct costs			24,032
Cash received from GulfTerra			(40,313)
Net cash payments			638,996
Value of non-cash consideration issued or granted			2,910,771
Total GulfTerra Merger consideration			3,549,767
Encinal acquisition, including non-cash equity consideration	$ 326,309	$	
Piceance Creek acquisition	100,000		
NGL underground storage and terminalling assets purchased from Ferrellgas		145,522	
Indirect interests in the Indian Springs natural gas gathering and processing assets		74,854	
Additional ownership interests in Dixie Pipeline Company (Dixie)	12,913	68,608	
Additional ownership interests in Mid-America and Seminole pipeline systems		25,000	
Other business combinations and asset purchases	18,390	12,618	85,851
Total	457,612	326,602	3,635,618
Capital spending for property, plant and equipment:			
Growth capital projects, net	1,148,123	719,372	113,759
Sustaining capital projects	132,455	98,077	33,169
Total	1,280,578	817,449	146,928
Capital spending attributable to unconsolidated affiliates:			

Investment in and advances to Jonah Gas Gathering Company	120,132		
Other investments in and advances to unconsolidated affiliates	7,290	88,044	64,412
Total	127,422	88,044	64,412
Total capital spending	$ 1,865,612	$ 1,232,095	$ 3,846,958

Our capital spending for growth capital projects (as presented in the preceding table) are net of amounts we received from third parties as contributions in aid of our construction costs. Such contributions were $60.5 million, $47.0 million and $8.9 million during 2006, 2005 and 2004, respectively. On certain of our capital projects, third parties are 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.

At December 31, 2006, we had $239.0 million in outstanding purchase commitments. These commitments primarily relate to growth capital projects in the Rocky Mountains that are expected to be placed in service in 2007 and the Shenzi Oil Export Pipeline Project (see below), which is expected to be completed in 2009.

Significant Recently Announced Growth Capital Projects

The following information summarizes our significant growth capital projects as of February 15, 2007. The capital spending amount noted for each project includes accrued expenditures and capitalized interest through December 31, 2006. The forecast amount noted for each project includes a provision for estimated capitalized interest.

Piceance Creek Acquisition. In December 2006, we purchased all of the membership interests in Piceance Creek from an affiliate of EnCana for $100 million. The assets of Piceance Creek consist primarily of the Piceance Creek Gathering System. As part of the transaction, EnCana signed a long-term, fixed-fee gathering contract and dedicated significant production to the system for the life of the associated lease holdings. The new Piceance Creek Gathering System has a transportation capacity of 1.6 Bcf/d and extends from a connection with EnCana s Great Divide Gathering System near Parachute, Colorado, northward through the Piceance Basin to our Meeker gas treating and processing complex, which is under construction. The Piceance Creek Gathering System commenced operations in January 2007.

Current natural gas production from the Piceance Basin, which covers approximately 6,000 square miles, exceeds 1 Bcf/d from more than 4,800 wells and has been growing at an annualized rate averaging 25% over the past five years. With third party estimates suggesting 20 trillion cubic feet of undeveloped reserves, the Piceance Basin offers long-term opportunities for us to continue to expand our system to serve producers developing this extensive resource play.

Barnett Shale Natural Gas Pipeline Project. In November 2006, we announced an expansion of our Texas Intrastate Pipeline with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. The Sherman Extension is supported by long-term contracts with Devon Energy Corporation, the largest producer in the Barnett Shale area, and significant indications of interest from leading producers and gatherers in the Fort Worth basin, as well as other shippers on our Texas Intrastate Pipeline system. At its terminus, the new pipeline system will make deliveries into Boardwalk Pipeline Partners L.P. s (Boardwalk) Gulf Crossing Expansion Project, which will provide export capacity for Barnett Shale natural gas production to multiple delivery points in Louisiana, Mississippi and Alabama that offer access to attractive markets in the Northeast and Southeast United States. In addition, the Sherman Extension will provide natural gas producers in East Texas and the Waha area of West Texas with access to these higher value markets through our Texas Intrastate Pipeline system.

The Sherman Extension will originate near Morgan Mill, Texas and extend through the center of the current Barnett Shale development area to Sherman, Texas. This new pipeline is expected to cost $424.6 million, most of which will be spent in 2008, and be placed in service during the fourth quarter of 2008. In addition, we have the option to acquire up to a 49% interest in Gulf Crossing Expansion Project from Boardwalk, subject to certain conditions.

The Barnett Shale is considered to be one of the largest unconventional natural gas resource plays in North America, covering approximately 14 counties and over seven million acres in the Fort Worth basin in North Texas. Current natural gas production is estimated at 2 Bcf/d from approximately 5,500 wells. Approximately 130 rigs are currently estimated to be working to develop Barnett Shale acreage in the region. According to the United States Geological Survey, the Barnett Shale has the resource potential of approximately 26 trillion cubic feet of natural gas.

Shenzi Oil Export Pipeline Project. In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The estimated construction cost of this new pipeline is approximately $172.4 million. As of December 31, 2006, our capital spending with respect to the Shenzi oil pipeline project was $6.8 million.

The Shenzi oil export pipeline will originate at the Shenzi Field, located in 4,300 feet of water at Green Canyon Block 653, approximately 120 miles off the coast of Louisiana. The 83-mile, 20-inch diameter pipeline will have the capacity to transport up to 230 MBPD of crude oil and will connect the Shenzi Field to our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B junction platform. We own a 50% interest in the Cameron Highway Oil Pipeline and a 36% interest in the Poseidon Oil Pipeline System and operate both pipelines. The Shenzi oil export pipeline will connect to a platform being constructed by BHP Billiton Plc to develop the Shenzi Field, which is expected to begin production in mid-2009.

Jonah Joint Venture with TEPPCO and the Phase V Expansion. In August 2006, we became a joint venture partner with TEPPCO in its Jonah subsidiary, which owns the Jonah Gathering System, located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System currently gathers and transports approximately 1.5 Bcf/d (or 85%) of natural gas produced from over 1,100 wells in the Jonah and Pinedale fields to regional natural gas processing plants, including our Pioneer plant, and major interstate pipelines that deliver natural gas to end-use markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO plan to continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.3 Bcf/d and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to 2.0 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $302.0 million. The second portion of the Phase V expansion is expected to cost approximately $142.0 million and be completed by the end of 2007. As of December 31, 2006, capital spending with respect to the overall Phase V Expansion (on a 100% basis) was $233.7 million.

We will continue to manage the Phase V construction project. TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and TEPPCO will share distributions based on a formula that takes into account the respective capital contributions of the parties, including expenditures by TEPPCO prior to the expansion. From August 1, 2006, we and TEPPCO share equally in the construction costs of the Phase V expansion.

As of December 31, 2006, TEPPCO reimbursed us $109.4 million for 50% of the Phase V expansion cost incurred through November 29, 2006 (including carrying costs of $1.3 million). We had a receivable of $8.7 million from TEPPCO at December 31, 2006 for costs incurred through December 31, 2006. Upon completion of the expansion project and based on the formula in the joint venture partnership agreement, we expect to own an interest in Jonah of approximately 20%, with TEPPCO owning the remaining 80%. We will operate the system. See Item 13 of this annual report for additional information regarding our relationship with TEPPCO.

DEP South Texas NGL Pipeline System. In August 2006, we acquired a 220-mile pipeline from ExxonMobil Pipeline Company for $97.7 million in cash. This pipeline originates in Corpus Christi, Texas and extends to Pasadena, Texas. This pipeline segment was expanded (the Phase I expansion) by (i) the construction of 45 miles of pipeline laterals to connect the system to our Armstrong and Shoup NGL fractionation facilities; (ii) the short-term lease from TEPPCO of a 11-mile interconnecting pipeline extending from Pasadena, Texas to Baytown, Texas; and (iii) the purchase of an additional 10-mile pipeline from TEPPCO that will connect the leased TEPPCO pipeline to Mont Belvieu, Texas. The purchase of the 10-mile segment from TEPPCO cost $8.0 million and was completed in January 2007. The primary term of the TEPPCO pipeline lease will expire in September 2007, and will continue on a month-to-month basis subject to customary termination provisions. Collectively, this 286-mile pipeline system will be termed the DEP South Texas NGL Pipeline. Phase I of the DEP South Texas NGL Pipeline System commenced transportation of NGLs in January 2007.

During 2007, we will construct an additional 21 miles of pipeline (the Phase II upgrade) to replace (i) the 11-mile pipeline we lease from TEPPCO and (ii) certain segments of the pipeline we acquired in August 2006 from ExxonMobil Pipeline Company. The Phase II upgrade is expected to provide a significant increase in pipeline capacity and be operational during the third quarter of 2007.

We estimate the cost of the Phase I expansion was $37.7 million, which included the $8 million we paid TEPPCO to acquire its 10-mile Baytown to Mont Belvieu pipeline. We expect the Phase II upgrade to cost an additional $28.6 million. As of December 31, 2006, our capital spending with respect to the DEP South Texas NGL Pipeline System was $117.8 million, which includes the $97.7 million we paid in August 2006.

This pipeline system is owned by South Texas NGL Pipelines, LLC, an entity that is 66% owned by Duncan Energy Partners and 34% by our Operating Partnership. For additional information regarding Duncan Energy Partners, see *Other Items Initial Public Offering of Duncan Energy Partners* included within this Item 7.

Texas Intrastate Pipeline Expansion Projects. In July 2006, we signed long-term agreements with CenterPoint Energy to provide firm natural gas transportation and storage services to its one of its natural gas utilities, primarily in the Houston, Texas metropolitan area. We will provide CenterPoint Energy with an estimated 14 Bcf per year of natural gas beginning in April 2007.

To provide these new services, we will enhance our Texas Intrastate natural gas pipeline system through a combination of pipeline and compression projects, including the expansion of our Wilson natural gas storage facility in Texas, acquisition of certain pipeline laterals located in the Houston, Texas area and the construction of eleven new city gate delivery stations.

The total capital cost of these projects is estimated to be $112.2 million and will be completed in phases extending through 2008. As of December 31, 2006, our capital spending with respect to these natural gas pipeline projects was $13.7 million. As part of this expansion project, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash in October 2006.

Encinal Acquisition. In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts and other assets that comprised the South Texas natural gas transportation and processing business of Lewis. The aggregate value of total consideration we paid or issued to complete this business combination, referred to as the Encinal acquisition, was $326.3 million.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas production wells producing from the Olmos and Wilcox formations. The Encinal system consists of 452 miles of pipeline, which is comprised of 280 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing South Texas natural gas pipeline system and are processed by our South Texas natural gas processing plants.

As part of this transaction, we acquired long-term natural gas processing and gathering dedications from Lewis. First, these gathering systems will be supported by a life of reserves gathering and processing dedication by Lewis related to its natural gas production from the Olmos formation. Second, Lewis entered into a 10-year agreement with us for the transportation of natural gas treated at its proposed Big Reef facility. This facility will treat natural gas production from the southern portion of the Edwards Trend in South Texas. Third, Lewis entered into a 10-year agreement with us for the gathering and processing of rich gas it produces from below the Olmos formation.

The total consideration paid or granted for the Encinal acquisition is summarized in the following table (dollars in thousands):

Cash payment to Lewis	$ 145,197
Fair value of our 7,115,844 common units issued to Lewis	181,112
Total consideration	$ 326,309

See Note 12 of the Notes to the Consolidated Financial Statements included under Item 8 of this annual report for our preliminary purchase price allocation related to this acquisition. As a result of our preliminary purchase price allocation, we recorded goodwill of $95.2 million, which management attributes to potential future benefits we may realize from our existing South Texas processing and NGL businesses as a result of the Encinal acquisition. Specifically, the long-term dedication rights acquired in connection with the Encinal acquisition are expected to add value to our South Texas processing facilities and related NGL businesses due to increased volumes.

Expansion of Import and Export Capability. In April 2006, we announced an expansion of our NGL import and export terminal located on the Houston Ship Channel. This expansion project will increase offloading capability of our import facility from a maximum peak operating rate of 240 MBPD to 480 MBPD and the maximum loading rate of our export facility from 140 MBPD to 160 MBPD. As part of this expansion project, we will increase the transportation and processing capacities of certain of our assets that serve the terminal in order to accommodate the expected increase in import volumes.

This expansion project is expected to cost approximately $62.7 million and be completed in the second quarter of 2007. As of December 31, 2006, our capital spending with respect to the expansion of import and export capabilities was $5.8 million.

Wyoming Gas Processing Projects. In March 2006, we paid $38.2 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After completing this asset purchase, we increased the capacity of the Pioneer natural gas processing plant from 300 MMcf/d to 600 MMcf/d at an additional cost of approximately $21 million. This expansion was completed in July 2006 and enables us to process natural gas production from the Jonah and Pinedale fields that will be transported to our Wyoming facilities as a result of the processing contract rights we acquired from TEPPCO. Of the $38.2 million we paid TEPPCO to acquire the Pioneer facility, $37.8 million was allocated to the contract rights we acquired.

In addition, to handle future production growth in the region and substantially increase NGL recoveries, we started construction of a new cryogenic natural gas processing plant in July 2006 adjacent to the Pioneer plant we acquired from TEPPCO. We expect our new natural gas processing plant, which will have the capacity to process up to 750 MMcf/d of natural gas, to be placed in service by the fourth quarter of 2007 at an expected cost of $236.2 million. As of December 31, 2006, our capital spending with respect to the new natural gas processing plant was $53.7 million.

Expansion of Mont Belvieu Petrochemical Assets. In March 2006, we announced an expansion of our petrochemical assets in Mont Belvieu and southeast Texas. This expansion project includes (i) the construction of a fourth propylene fractionator at our Mont Belvieu complex, which will increase our propylene/propane fractionation capacity by approximately 15 MBPD, and (ii) the expansion of two refinery grade propylene gathering pipelines which will add 50 MBPD of gathering capacity into Mont Belvieu. These projects are expected to be completed by late 2007 and cost approximately $204.1 million, which includes $35.0 million we spent in December 2005 to acquire a related pipeline asset. As of December 31, 2006, our capital spending with respect to these expansion projects was $142.8 million.

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 EnCana. Under that agreement, we 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. This processing plant will provide us with 750 MMcf/d of natural gas processing capacity and the ability to recover up to 35 MBPD of NGLs at full rates when Phase I of construction is completed in mid-2007. In addition, we will construct an approximate 50-mile NGL pipeline that will connect our Meeker facility with our Mid-America Pipeline System. The estimated cost of Phase I of the Meeker facility and related NGL pipeline is $320.7 million. EnCana has certain guaranteed payment obligations to us and we are currently working to secure production dedications from additional producers.

In June 2006, EnCana executed an option which requires us to build a 750 MMcf/d expansion of the Meeker facility by mid-2008 (the Phase II expansion). We have initiated design work on this expansion, which is expected to cost $260.6 million. This expansion will enable us to recover an additional 35 MBPD of NGLs at full rates. Under the terms of the agreement, EnCana has certain additional guaranteed payment obligations to us associated with the Phase II expansion.

As of December 31, 2006, our capital spending with respect to our Piceance Basin gas processing projects was $137.4 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. This project is expected to cost $232.5 million and be placed in service during the third quarter of 2007. Our Hobbs NGL fractionator will process the increase in mixed NGLs resulting from our Phase I expansion of the Mid-America Pipeline System. As of December 31, 2006, our capital spending with respect to the Hobbs NGL fractionator was $110.4 million.

Mid-America Pipeline System Projects. In January 2005, we announced an expansion (the Phase I expansion) of the Rocky Mountain segment of our Mid-America Pipeline System to accommodate expected increases in mixed NGL shipments originating from producing basins in Wyoming, Utah, Colorado and New Mexico. The Phase I expansion project will be completed in stages and will increase throughput volumes on the Rocky Mountain segment by 50 MBPD. We expect final completion of the Phase I expansion during the third quarter of 2007 at a cost of approximately $202.6 million.

As of December 31, 2006, our capital spending with respect to the Phase I expansion project was $128.6 million, including accrued expenditures. In August 2006, we executed new long-term transportation agreements with all but one of our current shippers on the Rocky Mountain segment of the Mid-America Pipeline System that will fully utilize this additional capacity.

In June 2005, we began engineering and design work to construct a 190-mile, 12-inch NGL pipeline that will have the capacity to move up to 67 MBPD of mixed NGLs bi-directionally between Skellytown, Texas and Conway, Kansas and an additional 48 MBPD from Skellytown, Texas to Hobbs, New Mexico. Construction of this pipeline began in the spring of 2006 and is expected to cost approximately $83.6 million and be placed in service in April 2007. As of December 31, 2006, our capital spending with respect to the Skellytown to Conway pipeline was $62.5 million.

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 the second half of 2007.

We constructed and own an 80% interest in the Independence Hub platform, which will be located in Mississippi Canyon Block 920, at a water depth of approximately 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. In January 2007, the Independence Hub platform sailed from its construction site in Corpus Christi, Texas to Mississippi Canyon Block 920, where it will be installed. We expect mechanical completion of the platform by mid-March 2007.

The platform, which is estimated to cost $445.9 million, will be operated by Anadarko (one of the major producers in the Atwater Valley Producers Group), and is designed to process production from its anchor fields and has excess payload capacity to support ten additional pipeline risers. As of December 31, 2006, our 80% share of capital spending with respect to the Independence Hub platform was $344.8 million.

During the third quarter of 2006, we completed construction of our 134-mile Independence Trail natural gas pipeline system, which has a throughput capacity of 1 Bcf/d of natural gas and will transport production from our Independence Hub platform to the Tennessee Gas Pipeline. This pipeline system and a related junction platform (under construction) are estimated to cost $281.3 million. We own 100% of the Independence Trail pipeline. As of December 31, 2006, our capital spending with respect to the Independence Trail pipeline and related junction platform was $271.3 million, including accrued expenditures.

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.

We spent approximately $64.6 million to comply with these programs during 2006, of which $26.4 million was recorded as an operating expense and the remaining $38.2 million was capitalized. During 2005, we spent approximately $42.2 million to comply with these programs, of which $25.0 million was recorded as an operating expense, and the remaining $17.2 million was capitalized.

We expect our net cash outlay for pipeline integrity program expenditures to approximate $48.0 million for 2007. Our forecast is net of certain costs we expect to recover from El Paso in connection with an indemnification agreement. 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. In 2006, we recovered $13.7 million from El Paso related to our 2005 expenditures. During 2007, we expect to recover $29.1 million from El Paso related to our 2006 expenditures, which leaves a remainder of $7.3 million reimbursable by El Paso for 2007 pipeline integrity costs.

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Results of Operations

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 financial 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 depreciation, amortization and accretion 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. Intercompany accounts and transactions are eliminated in consolidation.

We include earnings from equity method 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 and/or suppliers. 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. As circumstances dictate, we may increase our ownership interest in equity investments, which could result in their subsequent consolidation into our operations.

For additional information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Selected Price and Volumetric Data

The following table illustrates selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented.

	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)
2004 Averages	$6.13	$41.45	$0.50	$0.74	$0.88	$0.88	$1.00	$0.33	$0.29
2005 Averages	$8.64	$56.47	$0.62	$0.91	$1.09	$1.15	$1.26	$0.42	$0.37
2006									
1st Quarter	$9.01	$63.35	$0.57	$0.94	$1.20	$1.27	$1.38	$0.45	$0.40
2nd Quarter	$6.80	$70.53	$0.68	$1.05	$1.22	$1.26	$1.52	$0.50	$0.44
3rd Quarter	$6.58	$70.44	$0.76	$1.10	$1.28	$1.30	$1.53	$0.51	$0.46
4th Quarter	$6.56	$60.03	$0.62	$0.95	$1.11	$1.12	$1.31	$0.44	$0.35
2006 Averages	$7.24	$66.09	$0.66	$1.01	$1.20	$1.24	$1.44	$0.47	$0.41

(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.

	For the Year Ended December 31,		
	2006	**2005**	**2004**
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,577	1,478	1,411
NGL fractionation volumes (MBPD)	312	292	307
Equity NGL production (MBPD)(1)	63	68	76
Fee-based natural gas processing (MMcf/d)	2,218	1,767	1,692
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	6,012	5,916	5,638
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,520	1,780	2,081
Crude oil transportation volumes (MBPD)	153	127	138
Platform gas processing (BBtus/d)	159	252	306
Platform oil processing (MBPD)	15	7	14
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	81	81	76
Propylene fractionation volumes (MBPD)	56	55	57
Octane additive production volumes (MBPD)	9	6	10
Petrochemical transportation volumes (MBPD)	97	64	71
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,827	1,669	1,620
Natural gas transportation volumes (BBtus/d)	7,532	7,696	7,719
Equivalent transportation volumes (MBPD)(2)	3,809	3,694	3,651

(1)

Volumes for 2005 and 2004 have been revised to incorporate asset-level definitions of equity NGL production volumes.

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

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Comparison of Results of Operations

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

	For the Year Ended December 31,		
	2006	2005	2004
Revenues	$13,990,969	$12,256,959	$8,321,202
Operating costs and expenses	13,089,091	11,546,225	7,904,336
General and administrative costs	63,391	62,266	46,659
Equity in income of unconsolidated affiliates	21,565	14,548	52,787
Operating income	860,052	663,016	422,994
Interest expense	238,023	230,549	155,740
Net income	601,155	419,508	268,261

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

	For the Year Ended December 31,		
	2006	2005	2004
Gross operating margin by segment:			
NGL Pipelines & Services	$ 752,548	$ 579,706	$374,196
Onshore Natural Gas Pipelines & Services	333,399	353,076	90,977
Offshore Pipeline & Services	103,407	77,505	36,478
Petrochemical Services	173,095	126,060	121,515
Other, non-segment			32,025
Total segment gross operating margin	$1,362,449	$1,136,347	$655,191

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

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products during the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2006	2005	2004
NGL Pipelines & Services:			
Sale of NGL products	$9,496,926	$8,176,370	$5,542,877
Percent of consolidated revenues	68%	67%	67%
Onshore Natural Gas Pipelines & Services:			
Sale of natural gas	$1,230,369	$1,065,542	$ 686,770
Percent of consolidated revenues	9%	9%	8%
Petrochemical Services:			
Sale of petrochemical products	$1,545,693	$1,311,956	$1,054,994
Percent of consolidated revenues	11%	11%	13%

Comparison of Year Ended December 31, 2006 with Year Ended December 31, 2005

Revenues for 2006 were $14.0 billion compared to $12.3 billion for 2005. The increase in consolidated revenues year-to-year is primarily due to higher sales volumes and energy commodity prices in 2006 relative to 2005. These factors accounted for a $1.7 billion increase in consolidated revenues associated with our marketing activities. Revenues for 2006 include $63.9 million of proceeds from business interruption insurance associated with Hurricanes Katrina and Rita in 2005 and Hurricane Ivan in 2004.

Operating costs and expenses were $13.1 billion for 2006 versus $11.5 billion for 2005. The year-to-year increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our NGL and petrochemical products increased $1.2 billion year-to-year as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $258.7 million as a result of higher energy commodity prices in 2006 relative to 2005. General and administrative costs increased $1.1 million year-to-year primarily due to higher costs associated with FERC rate case filings associated with our Mid-America Pipeline System and Texas Intrastate System.

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 $1.00 per gallon during 2006 versus $0.91 per gallon during 2005, a year-to-year increase of 10%. 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 $7.24 per MMBtu during 2006 versus $8.64 per MMBtu during 2005. Polymer grade and refinery grade propylene index prices increased 12% year-to-year. For additional historical energy commodity pricing information, see the table on page 64.

Equity earnings from unconsolidated affiliates were $21.6 million for 2006 compared to $14.5 million for 2005. An increase in volumes from offshore production led to a collective $11.8 million increase year-to-year in equity earnings from Poseidon and Deepwater Gateway. Equity earnings from Cameron Highway increased $4.9 million year-to-year. Our equity earnings for 2005 included an $11.5 million charge associated with the refinancing of Cameron Highway s project finance debt. Also, equity earnings from our investment in Neptune decreased $10.3 million year-to-year primarily due to a $7.4 million non-cash impairment charge recorded in 2006 associated with this investment.

Operating income for 2006 was $860.1 million compared to $663 million for 2005. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $197.1 million increase in operating income year-to-year.

Interest expense increased $7.5 million year-to-year primarily due to our issuance of junior notes in 2006 and an increase in interest rates charged on our variable rate debt. Our average debt principal outstanding was $4.9 billion in 2006 compared to $4.6 billion in 2005.

As a result of items noted in the previous paragraphs, our consolidated net income increased $181.6 million year-to-year to $601.2 million in 2006 compared to $419.5 million in 2005. Net income for both years includes the recognition of non-cash amounts related to the cumulative effects of changes in accounting principles. We recorded a $1.5 million benefit in 2006 and a $4.2 million charge in 2005 related to such changes. For additional information regarding the cumulative effect of changes in accounting principles we recorded in 2006 and 2005, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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 $752.5 million for 2006 compared to $579.7 million for 2005. Segment gross operating margin for 2006 includes $40.4 million of proceeds from business interruption insurance claims related to Hurricanes Katrina, Rita and Ivan. We collected $4.8 million of proceeds from business interruption claims in 2005 related to Hurricane Ivan. Strong demand for NGLs in 2006 compared to 2005 led to higher natural gas processing margins, increased volumes of natural gas processed under fee-based contracts and higher NGL throughput volumes at certain of our pipelines and fractionation facilities.

Gross operating margin from NGL pipelines and storage was $265.7 million for 2006 compared to $203.0 million for 2005. Total NGL transportation volumes increased to 1,577 MBPD during 2006 from 1,478 MBPD during 2005. The $62.7 million year-to-year increase in gross operating margin is primarily due to higher NGL transportation and storage volumes at certain of our facilities and the affects of a higher average transportation rate charged to shippers on our Mid-America Pipeline System. Also, segment gross operating margin in 2006 from our Dixie pipeline system benefited from lower pipeline integrity and maintenance costs year-to-year and the settlement of claims associated with a pipeline contamination incident in 2005.

Gross operating margin from our natural gas processing and related NGL marketing business was $359.6 million for 2006 compared to $308.5 million for 2005. The $51.1 million increase in gross operating margin year-to-year is largely due to improved results from our south Texas and Louisiana natural gas processing facilities, which benefited from strong demand for NGLs, a favorable processing environment and higher levels of offshore natural gas production available for processing. Fee-based processing volumes increased to 2.2 Bcf/d during 2006 from 1.8 Bcf/d during 2005. Lastly, gross operating margin from natural gas processing for 2006 includes $9.6 million from processing contracts we acquired in connection with the Encinal acquisition in July 2006 and $9.4 million from the Pioneer plant, which we acquired from TEPPCO in March 2006 and subsequently expanded its capacity from 300 MMcf/d to 600 MMcf/d.

Gross operating margin from NGL fractionation was $86.8 million for 2006 compared to $63.4 million for 2005. Fractionation volumes increased from 292 MBPD during 2005 to 312 MBPD during 2006. The year-to-year increase in gross operating margin of $23.4 million is largely due to increased fractionation volumes at our Norco NGL fractionator. This facility suffered a reduction of volumes in the second half of 2005 due to the effects of Hurricanes Katrina and Rita. Also, our Mont Belvieu NGL fractionator benefited from a 15 MBPD expansion project that was completed during the second quarter of 2006.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $333.4 million for 2006 compared to $353.1 million for 2005. Our total onshore natural gas transportation volumes were 6,012 BBtu/d during 2006 compared to 5,916 BBtu/d for 2005. A $24.7 million increase in segment gross operating margin from our Texas Intrastate System year-to-year was more than offset by lower gross operating margin from our San Juan Gathering System and Wilson natural gas storage facility. Gross operating margin from our Texas Intrastate System increased to $117.7 million for 2006 from $93 million for 2005. Our Texas Intrastate System benefited from higher transportation fees and lower operating costs year-to-year.

Segment gross operating margin from our San Juan Gathering System decreased $26.7 million year-to-year attributable to lower revenues from certain gathering contracts in which the fees are based on an index price for natural gas. Average index prices for natural gas were significantly higher during 2005 relative to 2006 due to supply interruptions and higher regional demand caused by Hurricanes Katrina and Rita. Natural gas gathering volumes for the San Juan Gathering System were 1.2 BBtu/d for 2006 and 2005.

In addition, gross operating margin from this segment decreased $21.9 million year-to-year as a result of mechanical problems associated with three storage caverns located at our Wilson natural gas storage facility in Texas, which caused these wells to be taken out of service for most of 2006. This includes $7.9 million in losses associated with the withdrawal of cushion gas from these wells.

Lastly, gross operating margin for 2006 includes $1.8 million from the Encinal Gathering System that we acquired in July 2006. The Encinal Gathering System contributed 89 BBtu/d of gathering volumes during 2006.

Offshore Pipelines & Services. Gross operating margin from this business segment was $103.4 million for 2006 compared to $77.5 million for 2005. Segment gross operating margin for 2006 includes $23.5 million of proceeds from business interruption insurance claims related to Hurricanes Katrina, Rita and Ivan. As a result of industry losses associated with these storms, insurance costs for offshore operations have increased dramatically. Insurance costs for our offshore assets were $21.6 million for 2006 compared to $6.5 million for 2005.

Gross operating margin from our offshore crude oil pipelines was $23.0 million for 2006 versus $0.3 million for 2005. Our Marco Polo and Poseidon oil pipelines posted higher crude oil transportation volumes during 2006 due to increased production activity by our customers. Collectively, gross operating margin from the Marco Polo and Poseidon oil pipelines improved $10.1 million year-to-year. Our Constitution Oil Pipeline, which was placed in-service during the first quarter of 2006, contributed $8.8 million to segment gross operating margin during 2006. Total offshore crude oil transportation volumes were 153 MBPD during 2006 versus 127 MBPD during 2005.

Gross operating margin from our offshore natural gas pipelines was $22.4 million for 2006 compared to $37.1 million for 2005. Offshore natural gas transportation volumes were 1,520 BBtu/d during 2006 versus 1,780 BBtu/d during the third quarter of 2005. The $14.7 million decrease in gross operating margin year-to-year is largely due to increased insurance costs and a non-cash impairment charge of $7.4 million recorded in 2006 associated with our investment in Neptune. Also, 2006 includes gross operating margin of $8.4 million and transportation volumes of 50 BBtu/d from the Constitution natural gas pipeline, which was placed in service during the first quarter of 2006.

Gross operating margin from our offshore platforms was $34.5 million for 2006 compared to $40.1 million for 2005. The decrease in gross operating margin year-to-year is primarily due to reduced offshore production as a result of Hurricanes Katrina and Rita in 2005. Equity earnings from Deepwater Gateway, which owns the Marco Polo platform, increased $7.8 million year-to-year primarily due to higher processing volumes.

Petrochemical Services. Gross operating margin from this business segment was $173.1 million for 2006 compared to $126.1 million for 2005. The $47 million year-to-year increase in gross operating margin is primarily due to improved results from our octane enhancement business attributable to higher isooctane sales volumes and prices. Gross operating margin from this business was $36.5 million for 2006 compared to $3.6 million for the 2005. Isooctane, a high octane, low vapor pressure motor gasoline additive, complements the increasing use of ethanol, which has a high vapor pressure. Our isooctane production facility commenced operations in the second quarter of 2005.

Gross operating margin from our propylene fractionation and pipeline activities was $63.4 million for 2006 versus $55.9 million for 2005. The year-to-year increase in gross operating margin of $7.5 million is primarily due to improved polymer grade propylene sales prices and volumes and the addition of the Texas City refinery-grade propylene pipeline, which we completed during 2005. Petrochemical transportation volumes were 97 MBPD during 2006 compared to 64 MBPD during 2005. Gross operating margin from butane isomerization was $73.2 million for 2006 compared to $66.6 million for 2005. The year-to-year increase of $6.6 million is primarily due to higher processing fees and lower fuel costs. Butane isomerization volumes were 81 MBPD during 2006 and 2005.

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

Revenues for 2005 were $12.3 billion compared to $8.3 billion for 2004. The increase in consolidated revenues is due in part to an increase in NGL and petrochemical sales volumes and higher energy commodity prices in 2005 relative to 2004. These differences accounted for a $2.4 billion increase in revenues from our natural gas, NGL and petrochemical marketing activities. Also, our consolidated revenues increased by $1.5 billion year-to-year attributable to revenues earned by acquired or consolidated businesses, particularly those generated by the GulfTerra and South Texas midstream assets.

Operating costs and expenses were $11.5 billion for 2005 compared to $7.9 billion for 2004. The year-to-year increase in consolidated costs and expenses is 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 $15.6 million year-to-year as a result of our 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 $0.91 per gallon during 2005 versus $0.73 per gallon during 2004 a year-to-year increase of 25%. The Henry Hub market price for natural gas 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 additional historical energy commodity pricing information, see the table on page 64.

Equity earnings from unconsolidated affiliates were $14.5 million for 2005 versus $52.8 million for 2004. 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 $32.0 million of equity earnings from GulfTerra GP, which we consolidated in September 2004 as a result of completing the GulfTerra Merger.

Operating income for 2005 was $663.0 million compared to $423.0 million for 2004. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $240 million increase in operating income year-to-year.

Interest expense increased $74.8 million year-to-year primarily due to debt that was incurred in 2004 as a result of the GulfTerra Merger and the issuance of additional senior notes in 2005. Our average debt principal outstanding was $4.6 billion in 2005 compared to $2.8 billion in 2004.

As a result of items noted in the previous paragraphs, our consolidated net income increased $151.2 million year-to-year to $419.5 million in 2005 compared to $268.3 million in 2004. Net income for both years includes the recognition of non-cash amounts related to the cumulative effects of changes in accounting principles. We recorded a $4.2 million charge in 2005 and a $10.8 million benefit in 2004 related to such changes. For additional information regarding the cumulative effect of changes in accounting principles we recorded in 2005 and 2004, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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 year-to-year increase in gross operating margin is primarily due to assets we acquired in connection with the GulfTerra Merger. Also, this business segment was impacted by the varying effects of Hurricanes Katrina (August 2005) and Rita (September 2005), both significant storms. In general, 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 effects were mitigated by increases in gross operating margin from certain of our other operations, which benefited from increased demand for NGLs, regional demand for natural gas and a general increase in commodity prices. We collected $4.8 million of proceeds from business interruption claims in 2005 related to Hurricane Ivan.

Segment gross operating margin from our natural gas processing and related NGL marketing business was $308.5 million for 2005 compared to $123.6 million for 2004. The $184.9 million year-to-year increase includes $122.3 million of gross operating margin from natural gas processing plants we acquired in connection with the GulfTerra Merger. Gross operating margin from our NGL marketing activities increased $66.9 million year-to-year due to higher sales volumes and energy commodity prices during 2005 relative to 2004.

Gross operating margin from NGL fractionation was $63.4 million for 2005 compared to $42.6 million for 2004. The $20.8 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 $9.0 million decrease from our Louisiana NGL fractionators, particularly Norco, which suffered a loss of processing volumes due to Hurricane Katrina.

Gross operating margin from NGL pipelines and storage was $203.0 million for 2005 compared to $208.0 million for 2004. The $5.0 million year-to-year decrease in gross operating margin from NGL pipelines and storage 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 $91.0 million for 2004. The $262.1 million increase in gross operating margin year-to-year 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 of $290.4 million in 2005. 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 $41.0 million increase in gross operating margin year-to-year 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 our butane isomerization and octane enhancement businesses, 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.

Significant Risks and Uncertainties Hurricanes

EPCO renewed its property and casualty insurance programs during the second quarter of 2006. As a result of severe hurricanes such as Katrina and Rita that occurred in 2005, market conditions for obtaining property damage insurance coverage were difficult. Under our renewed insurance programs, coverage is more restrictive, including increased physical damage and business interruption deductibles. For example, our deductible for onshore physical damage increased from $2.5 million to $5 million per event and our deductible period for onshore business interruption claims increased from 30 days to 60 days. Additional restrictions will also be applied in the event of damage from named windstorms.

In addition to changes in coverage, the cost of property damage insurance increased substantially from prior periods. At present, our annualized cost of insurance premiums for all lines of coverage is approximately $49.2 million, which represents a $28.1 million (or 133%) increase from our 2005 annualized insurance cost.

The following is a discussion of the general status of insurance claims related to significant storm events that affected our assets in 2004 and 2005. To the extent we include 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 related to the merger of GulfTerra with a wholly owned subsidiary of Enterprise Products Partners in September 2004 (the GulfTerra Merger) included a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain pre-merger GulfTerra assets caused by Hurricane Ivan. During 2006, 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 in 2007. 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 2006, we received $17.4 million of nonrefundable cash proceeds from such claims. We are continuing our efforts to collect residual balances and expect to complete the process during 2007. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as a gain in our Statements of Consolidated Operations 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. The majority of repairs to our facilities are completed; however, certain minor repairs are ongoing to two offshore pipelines and an onshore gas processing facility. To the extent that insurance proceeds from property damage claims are not probable of collection or do not cover our estimated expenditures (in excess of $5.0 million of insurance deductibles we expensed during 2005), such amounts are charged to earnings when realized. With respect to these storms, we have $78.2 million of estimated property damage claims outstanding at December 31, 2006, that we believe are probable of collection during the period 2007 through 2009. For the year ended December 31, 2006, we received $10.5 million of physical damage proceeds related to such storms (dollars in thousands).

In addition, we received $46.5 million of nonrefundable cash proceeds from business interruption claims during the year ended December 31, 2006. We are aggressively pursuing collection of our remaining property damage and business interruption claims related to Hurricanes Katrina and Rita.

The following table summarizes proceeds we received during 2006 from business interruption and property damage insurance claims with respect to certain named storms (dollars in thousands).

Business interruption proceeds:	
Hurricane Ivan	$ 17,382
Hurricane Katrina	24,500
Hurricane Rita	22,000
Total proceeds	$ 63,882
Property damage proceeds:	
Hurricane Ivan	$ 24,104
Hurricane Katrina	7,500
Hurricane Rita	3,000
Total proceeds	$ 34,604
Total proceeds received during 2006	$ 98,486

During 2005, we received $4.8 million of nonrefundable cash proceeds from business interruption claims.

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General Outlook for 2007

We are currently in a major asset construction phase that began in 2005. Fiscal 2007 will be a transition year as we take several major projects from the construction phase and place them in-service. In addition, we have continued to grow our relationships with customers by executing several long-term natural gas gathering and processing agreements with major producers to support our newly constructed assets. As we further expand our portfolio of midstream assets, we expect our results of operations to be affected by the following key trends and events during 2007.

- We believe that drilling activity in the major producing areas where we operate, including the Gulf of Mexico and supply basins in Texas, San Juan and the Rocky Mountains, will result in increased demand for our midstream energy services. As a result, we expect higher transportation and processing volumes for our existing assets due to increased natural gas and crude oil production from both onshore and offshore producing areas. In addition, we expect to benefit from increased demand as new assets come on-line during 2007.

- We expect to benefit from an increase in crude oil and natural gas production in the Gulf of Mexico as our Independence Hub platform and Independence Trail pipeline are placed in-service during the second half of 2007. Our Independence Hub platform and Independence Trail pipeline will benefit from initial natural gas production from dedicated production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. In addition, we believe that our Marco Polo Oil Pipeline and Marco Polo platform will continue to benefit as production volumes increase from developments in the Southern Green Canyon area of the Gulf of Mexico. Increased production in the Gulf of Mexico will increase volumes of natural gas and NGLs available to our facilities in southern Louisiana.

- We expect the volume of natural gas and NGLs available to our facilities in Texas to increase as a result of drilling activity and long-term agreements executed with new customers. We expect natural gas transportation volumes on our Texas Intrastate System to increase during 2007 as we begin to supply the Houston, Texas area with natural gas volumes under a long-term agreement with CenterPoint Energy. As a result of the Encinal acquisition, we expect to increase natural gas gathering and processing volumes in south Texas. In turn, this should increase our NGL production in south Texas. In addition, we will continue to expand our natural gas gathering assets in the Barnett shale region of north Texas.

- We expect to benefit from increased natural gas and NGL volumes as several new assets are placed in-service throughout Wyoming, Colorado and New Mexico. We expect our new Pioneer natural gas processing plant and expanded Jonah Gathering System to benefit from increased production in the Greater Green River basin of Wyoming. Production from the Piceance basin of western Colorado should benefit our Piceance Creek Gathering System and Meeker natural gas processing plant. We expect our Mid-America Pipeline System, Seminole Pipeline and Hobbs NGL fractionator to benefit from increased volumes of NGLs produced at the Pioneer and Meeker natural gas processing facilities.

- We believe that the strength of the domestic and global economy will continue to drive increased demand for all forms of energy despite fluctuating commodity prices. Our largest NGL consuming customers in the ethylene industry continue to see strong demand for their products. Ethane and propane continue to be the preferred feedstocks for the ethylene industry with the high price of crude oil relative to natural gas.

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Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to our partners. 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 credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interest in assets to affiliates or third parties. We expect to fund cash distributions to partners 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, 2006, we had $22.6 million of unrestricted cash on hand and approximately $790.1 million of available credit under our Operating Partnership s Multi-Year Revolving Credit Facility. In total, we had approximately $5.3 billion in principal outstanding under various debt agreements at December 31, 2006.

As a result of our 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 an investment grade credit rating 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 our growth strategy, see *Capital Spending* included within this Item 7.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. In March 2005, we 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 past issuance of securities under this universal registration statement, we can issue approximately $2.1 billion of additional securities under this registration statement as of February 1, 2007.

Our significant issuances of partnership equity during the year ended December 31, 2006 were as follows:

- In March 2006, we sold 18,400,000 common units (including an over-allotment amount of 2,400,000 common units) to the public at an offering price of $23.90 per unit. Net proceeds from this offering, including Enterprise Products GP s proportionate net capital contribution of $8.6 million, were approximately $430 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $18.3 million. The net proceeds from this offering, including Enterprise Products GP s proportionate net capital contribution, were used to temporarily reduce indebtedness outstanding under our Operating Partnership s Multi-Year Revolving Credit Facility.

- In July 2006, we issued approximately 7.1 million of our common units in connection with the Encinal business acquisition. In August 2006, we filed a registration statement with the SEC for the resale of these common units.

- In September 2006, we sold 12,650,000 common units (including an over-allotment amount of 1,650,000 common units) to the public at an offering price of $25.80 per unit. Net proceeds from this offering, including Enterprise Products GP s proportionate net capital contribution of $6.4

million, were approximately $320.8 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $11.8 million. Net proceeds of $260 million from this offering, including Enterprise Products GP s proportionate net capital contribution, were used to temporarily reduce indebtedness outstanding under our Operating Partnership s Multi-Year Revolving Credit Facility. The remaining net proceeds were used for general partnership purposes.

During 2003, we instituted a distribution reinvestment plan (DRIP). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. We have a registration statement on file with the SEC covering the issuance of up to 15,000,000 common units in connection with the DRIP. During the year ended December 31, 2006, we issued 3,639,949 common units in connection with our DRIP, which generated proceeds of $91.6 million from plan participants. These proceeds include $50 million reinvested by EPCO in August 2006 with respect to its beneficial ownership of our common units. A total of 1,966,354 common units were issued to EPCO as a result of this reinvestment in our partnership.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the year ended December 31, 2006, we issued 134,700 common units to employees under this plan, which generated proceeds of $3.4 million.

In February 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units, the majority of proceeds from which were distributed to us. Duncan Energy Partners may issue additional amounts of equity in the future in connection with other acquisitions. For additional information regarding Duncan Energy Partners, see *Other Items Initial Public Offering of Duncan Energy Partners*.

For information regarding our public debt obligations or partnership equity, see Notes 14 and 15, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Credit Ratings of Operating Partnership

At February 27, 2007, the investment-grade credit ratings of our Operating Partnership s debt securities were Baa3 by Moody s Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor s. All three ratings services have assigned to us a stable outlook with respect to their judgment of our future business performance.

Based on the characteristics of the fixed/floating unsecured junior subordinated notes that the Operating Partnership issued during the third quarter of 2006, the rating agencies assigned partial equity treatment to the notes. Moody s Investor Services and Standard and Poor s each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

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 declining below BBB-, the $54.0 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, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Debt Obligations

For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, see 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):

	At December 31, 2006	At December 31, 2005
Operating Partnership senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011 (1)	$ 410,000	$ 490,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
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	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	10,000	17,000
Other, 8.75% fixed-rate, due June 2010 (5)	5,068	5,068
Total principal amount of senior debt obligations	4,779,068	4,866,068
Operating Partnership Junior Subordinated Notes A, due August 2066	550,000	
Total principal amount of senior and junior debt obligations	5,329,068	4,866,068
Other, including unamortized discounts and premiums and changes in fair value (3)	(33,478)	(32,287)
Long-term debt(4)	$ 5,295,590	$ 4,833,781
Standby letters of credit outstanding	$ 49,858	$ 33,129

(1) In June 2006, the Operating Partnership executed a second amendment (the Second Amendment) to the credit agreement governing its Multi-Year Revolving Credit Facility.

The Second Amendment, among other things, extends the maturity date of amounts borrowed under the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.25 billion of the commitments. Borrowings with respect to the remaining $48 million in commitments mature in October 2010.

(2) The maturity date of this facility was extended from June 2007 to June 2010 in August 2006. The other terms of the Dixie facility remain unchanged from those described in our annual report on Form 10-K for the year ended December 31, 2005. In accordance with GAAP, we consolidated Dixie s debt with that of our own; however, we are not obligated to make interest or

debt payments with respects to Dixie s debt.

(3) The December 31, 2006 amount includes $29.1 million related to fair value hedges and a net $4.4 million in unamortized discounts and premiums. The December 31, 2005 amount includes $19.2 million related to fair value hedges and a net $13.1 million in unamortized discounts and premiums.

(4) In accordance with SFAS 6, *Classification of Short-Term Obligations Expected to be Refinanced*, long-term and current maturities of debt reflects the classification of such obligations at December 31, 2006. With respect to Senior Notes E due in October 2007, the Operating Partnership has the ability to use available credit capacity under

its Multi-Year Revolving Credit Facility to fund the repayment of this debt.

(5) Represents the remaining debt obligations assumed in connection with the GulfTerra merger.

Issuance of Junior Subordinated Notes A. The Operating Partnership sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 during the third quarter of 2006. The Operating Partnership used the proceeds from issuing this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Operating Partnership s payment obligations under the Junior Subordinated Notes A are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under the Junior Subordinated Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing the Junior Subordinated Notes A allows the Operating Partnership to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on the Junior

Subordinated Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the Indenture has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, then the Operating Partnership and we cannot declare or make any distributions with respect to any of their respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or subordinate to the Junior Subordinated Notes A.

The Junior Subordinated Notes A will bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, commencing in February 2007. After August 2016, the Junior Subordinated Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Subordinated Notes A mature in August 2066 and are not redeemable by the Operating Partnership prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of the Junior Subordinated Notes A, the Operating Partnership entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which the Operating Partnership agreed for the benefit of such debt holders that it would not redeem or repurchase such junior subordinated notes unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Based on the characteristics of the Junior Subordinated Notes A, rating agencies assigned partial equity treatment to the notes. Moody s Investor Services and Standard and Poor s each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

Debt obligations of unconsolidated affiliates. The following table summarizes the debt obligations of our unconsolidated affiliates (on a 100% basis to the joint venture) at December 31, 2006 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%	91,000
Evangeline	49.5%	25,650
Total		$ 531,650

In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays caused by the lingering effects of Hurricanes Katrina and Rita. In general, this amendment modified certain financial covenants in light of production forecasts. In addition, the amendment increased the letters of credit required to be issued by the Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

In September 2006, Fitch Ratings reaffirmed its BBB- rating (with a negative outlook) of Cameron Highway s privately placed senior secured notes. The rating was placed on watch in March 2006 due to the near-term financial impact of lower than anticipated volumes on the Cameron Highway Oil Pipeline. While Fitch continues to believe that the current volume shortfalls are temporary, particularly with completion of the Atlantis development expected in the first quarter of 2007, if transportation volumes remain impaired over the next several months Fitch will likely lower the rating. Currently, production from Atlantis is expected to commence by the end of 2007. If the rating falls below BBB-, the interest rates paid by Cameron Highway will increase by 1% to 1.5% per annum depending on the lower rating.

In May 2006, Poseidon amended its revolving credit facility, which, among other things, decreased the availability to $150.0 million from $170.0 million, extended the maturity date from January 2008 to May 2011 and lowered the borrowing rate.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our 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, see the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For the Year Ended December 31,		
	2006	**2005**	**2004**
Net cash flows provided by operating activities	$1,175,069	$ 631,708	$391,541
Net cash used in investing activities	1,689,288	1,130,395	941,424
Net cash provided by financing activities	494,972	516,229	543,973

Net cash flows provided by 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, see 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, 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.

Our Statements of Consolidated Cash Flows are prepared 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 similar transactions, (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, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization, operating lease expense paid by EPCO and changes in the fair market value of financial instruments. Equity in income from unconsolidated affiliates is also a non-cash item that must be removed in determining net cash provided by operating activities. Our cash flows from operating activities reflect the actual cash distributions we receive from such investees.

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 are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

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

Comparison of Year Ended December 31, 2006 with Year Ended December 31, 2005

Operating activities. Net cash flows provided by operating activities for the year ended December 31, 2006 increased $543.4 million over that recorded for the year ended December 31, 2005. In addition to changes in our earnings and other factors as described below, cash flows from operating activities are influenced by the timing of cash receipts and disbursements. The following information highlights factors that influenced the year-to-year change in cash flows provided by operating activities:

Gross operating margin for the year ended December 31, 2006 increased $226.1 million over that recorded for the year ended December 31, 2005. The increase in gross operating margin is discussed under *Results of Operations* within this Item 7.

With respect to changes in operating accounts, the timing of cash receipts and disbursements improved year-to-year generally due to the successful integration of acquired businesses and increased efficiencies. As to cash receipts, the average collection period for accounts receivable during the year ended December 31, 2006 improved approximately nine days when compared to the year ended December 31, 2005, with the related turnover rate increasing 26% year-to-year. In addition, as to cash disbursements, our payable turnover rate increased significantly year-to-year.

Investing activities. Cash used in investing activities was $1.7 billion for the year ended December 31, 2006 compared to $1.1 billion for the year ended December 31, 2005.

Our cash outlays for business combinations were $276.5 million in 2006 versus $326.6 million in 2005. During the year ended December 31, 2006, we paid $100.0 million for a 100% interest in Piceance Creek Pipeline, LLC and paid Lewis $145.2 million in cash in connection with the Encinal acquisition. Our cash outlay for acquisitions during 2005 included (i) $145.5 million for storage assets purchased from Ferrellgas LP, (ii) $74.9 million for indirect interests in certain East Texas natural gas gathering and processing assets, (iii) $68.6 million for additional ownership interests in Dixie and (iv) $25.0 million for the remaining ownership interests in our Mid-America Pipeline System and an additional interest in the Seminole Pipeline.

Proceeds from the sale of assets during 2005 include $42.1 million from the sale of our investment in Starfish Pipeline Company, LLC (Starfish). We were required to divest our ownership interest in this entity by the Federal Trade Commission in order to gain its approval for our merger with GulfTerra Energy Partners, L.P. in September 2004. In addition, we received $47.5 million as a return of our investment in Cameron Highway in June 2005. As a result of refinancing its project debt, Cameron Highway was authorized by its lenders to make this special distribution.

Investments in unconsolidated affiliates were $138.3 million for the year ended December 31, 2006 compared to $87.3 million for the year ended December 31, 2005. The 2006 period includes $120.1 million we invested to date in Jonah. The 2005 period primarily reflects $72.0 million we contributed to Deepwater Gateway to fund our share of the repayment of its construction loan in March 2005.

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

Financing activities Cash provided by financing activities was $495.0 million for the year ended December 31, 2006 compared to $516.2 million for the year ended December 31, 2005. As a result of our capital spending program, we utilized the Operating Partnership s Multi-Year Revolving Credit Facility in varying degrees throughout 2006. During 2006, we applied all or a portion of the net proceeds from equity and debt offerings to reduce debt outstanding. We used $430 million of net proceeds from our March 2006 equity offering and $260 million of net proceeds from our September 2006 equity offering to temporarily reduce amounts due under the Multi-Year Revolving Credit Facility. We also used the net proceeds from the Operating Partnership s issuance of Junior Subordinated Notes A in the third quarter of 2006 to reduce debt outstanding under this facility. We used any remaining net proceeds from these offerings in 2006 for general partnership purposes.

During 2005, our Operating Partnership issued an aggregate of $1 billion in senior notes, the proceeds of which were used to repay $350 million due under Senior Notes A, to temporarily reduce amounts outstanding under our bank credit facilities and for general partnership purposes. Additionally, we repaid the remaining $242.2 million that was due under our 364-Day Acquisition Credit Facility (which was used to finance elements of the GulfTerra Merger) using proceeds generated from our February 2005 equity offering.

Net proceeds from the issuance of our limited partner interests were $857.2 million for 2006 compared to $646.9 million for 2005. With respect to equity offerings (including sales through our distribution reinvestment program and employee unit purchase plan), we issued 34,824,649 common units 2006 versus 23,979,740 common units during 2005. Net proceeds from underwritten equity offerings were $750.8 million during 2006 reflecting the sale of 31,050,000 common units and $555.5 million during 2005 reflecting the sale of 21,250,000 common units. Our distribution reinvestment program and related employee unit purchase plan generated net proceeds of $96.9 million during 2006, including $50 million reinvested by EPCO. In comparison, this program generated proceeds of $69.7 million during 2005, including $30 million reinvested by EPCO.

Cash distributions to partners increased from $716.7 million during 2005 to $843.3 million during 2006. The period-to-period increase in cash distributions is due to an increase in common units outstanding and quarterly cash distribution rates. Cash contributions from minority interests were $27.6 million for 2006 compared to $39.1 million for 2005.

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

Operating activities. Net cash flows provided by operating activities for the year ended December 31, 2005 increased $240.2 million over that recorded for the year ended December 31, 2004. The following information highlights factors that influenced the year-to-year change in cash flows provided by operating activities:

Gross operating margin for the year ended December 31, 2005 increased $481.2 million over that recorded for the year ended December 31, 2004. The increase in gross operating margin is discussed under *Results of Operations* within this Item 7.

Cash payments for interest for the year ended December 31, 2005 increased $103.3 million over that recorded for the year ended December 31, 2004. The increase in cash outflows for interest was due to the additional debt we incurred to complete the GulfTerra Merger.

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.

With respect to changes in operating accounts, the timing of cash disbursements slowed following the GulfTerra Merger as integration activities were ongoing. A slight improvement in the collection of accounts receivable also added to our operating cash flows.

Investing activities. Cash used in investing activities was $1.1 billion in 2005 compared to $941.4 million 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 business combinations were $326.6 million in 2005 versus $724.7 million in 2004. The 2004 period includes $638.8 million 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 $72.0 million to Deepwater Gateway to fund our share of the repayment of its term loan. During 2004, we used $27.5 million to acquire additional ownership interests in Promix, which owns the Promix NGL fractionator, and contributed $24.0 million to 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. The sale of our Starfish investment was required by the FTC in order to gain its approval for the GulfTerra Merger.

Financing activities. Cash provided by financing activities was $516.2 million in 2005 compared to $544.0 million in 2004. We had net borrowings under our debt agreements of $561.7 million during 2005 versus $125.6 million during 2004. During 2005, we issued an aggregate $1 billion in senior notes, the proceeds of which were used to temporarily reduce debt outstanding under our bank credit facilities, repay Senior Notes A and for general partnership purposes, including capital expenditures, asset purchases and business combinations. In addition, we repaid the remaining $242.2 million that was outstanding at the end of 2004 under our 364-Day Acquisition Credit Facility using proceeds from our February 2005 equity offering. We used the net proceeds from our November 2005 equity offering to temporarily reduce amounts outstanding under our Multi-Year Revolving Credit Facility.

In September 2004, we borrowed $2.8 billion under our 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 our tender offers; and repay $962 million outstanding under GulfTerra s revolving credit facility and secured term loans. In October 2004, we issued an aggregate $2 billion in senior notes, the proceeds of which were used to reduce indebtedness outstanding under our bank credit facilities. Our repayments of debt during 2004 also reflect the use of $563.1 million of net proceeds from our May 2004 and August 2004 equity offerings to reduce indebtedness under bank credit facilities.

Net proceeds from the issuance of limited partner interests were $646.9 million in 2005 compared to $846.1 million in 2004. We issued 23,979,740 common units in 2005 and 39,683,591 common units in 2004. Net proceeds from underwritten equity offerings were $555.5 million during 2005 reflecting the sale of 21,250,000 units and $694.3 million during 2004 reflecting the sale of 34,500,000 units. We used net proceeds from these underwritten offerings to reduce debt, including the temporary repayment of indebtedness under bank credit facilities. Our distribution reinvestment program and related plan generated net proceeds of $69.7 million in 2005 and $111.6 million in 2004. We used net proceeds from these offerings for general partnership purposes. For additional information regarding our equity issuances, please read Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Cash distributions to partners increased from $438.8 million in 2004 to $716.7 million in 2005 primarily due to an increase in common units outstanding and our quarterly cash distribution rates. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units. Cash contributions from minority interests were $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.

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 prospectively. 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, 2006 and 2005, the net book value of our property, plant and equipment was $9.8 billion and $8.7 billion, respectively. We recorded $352.2 million, $328.7 million and $161.0 million in depreciation expense for the years ended December 31, 2006, 2005 and 2004, 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, see 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.

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.

We recognized non-cash asset impairment charges related to property, plant and equipment of $0.1 million in 2006 and $4.1 million in 2004, which are reflected as components of operating costs and expenses. No such asset impairment charges were recorded in 2005.

During 2006, we evaluated our equity method investment in Neptune Pipeline Company, L.L.C. for impairment. As a result of this evaluation, we recorded a $7.4 million non-cash impairment charge that is a component of equity income from unconsolidated affiliates for the year ended December 31, 2006. We had no such impairment charges during the years ended December 31, 2005 or 2004. For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see 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 business combinations and asset purchases. 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, 2006 and 2005, the carrying value of our intangible asset portfolio was $1.0 billion and $913.6 million, respectively. We recorded $88.8 million, $88.9 million and $33.8 million in amortization expense associated with our intangible assets for the years ended December 31, 2006, 2005 and 2004, 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, see 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 $385.9 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, 2006 and 2005, the carrying value of our goodwill was $590.5 million and $494.0 million, respectively. We did not record any goodwill impairment charges during the years ended December 31, 2006, 2005 and 2004.

For additional information regarding our goodwill, see 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 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. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

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 instances, 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.

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At December 31, 2006 and 2005, we had a liability for environmental remediation of $24.2 million and $22.1 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of AICPA Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities.

See Item 3 of this annual report for recent developments regarding environmental matters.

Natural gas imbalances

In the pipeline transportation business, natural gas imbalances frequently result from differences in gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several months. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2006 and 2005, our imbalance receivables, net of allowance for doubtful accounts, were $97.8 million and $89.4 million, respectively, and are reflected as a component of Accounts and notes receivable trade on our Consolidated Balance Sheets. At December 31, 2006 and 2005, our imbalance payables were $51.2 million and $80.5 million, respectively, and are reflected as a component of Accrued gas payables on our Consolidated Balance Sheets.

Other Items

Initial Public Offering of Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.3 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,371,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,371,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under our Multi-Year Revolving Credit Facility.

In summary, we contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

Mont Belvieu Caverns, LLC (Mont Belvieu Caverns), a recently formed subsidiary, which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;

Acadian Gas, LLC (Acadian Gas), which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns a 49.5% equity interest in Evangeline Gas Pipeline, L.P. (Evangeline);

Sabine Propylene Pipeline L.P. (Sabine Propylene), which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;

Enterprise Lou-Tex Propylene Pipeline L.P. (Lou-Tex Propylene), which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and

South Texas NGL Pipelines, LLC (South Texas NGL), a recently formed subsidiary, which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition, to the 34% ownership interest we retained in each of these entities, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners outstanding common units. Our Operating Partnership directs the business operations of Duncan Energy Partners through its ownership and control of the general partner of Duncan Energy Partners.

The formation of Duncan Energy Partners had no effect on our financial statements at December 31, 2006. For financial reporting purposes, the consolidated financial statements of Duncan Energy Partners will be consolidated into those of our own. Consequently, the results of operations of Duncan Energy Partners will be a component of our business segments. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners will reflect our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners.

The public owners of Duncan Energy Partners common units will be presented as a noncontrolling interest in our consolidated financial statements beginning in February 2007. The public owners of Duncan Energy Partners have no direct equity interests in us as a result of this transaction. The borrowings of Duncan Energy Partners will be presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We have significant continuing involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;

We buy natural gas from and sell natural gas to Acadian Gas in connection with its normal business activities; and

We are the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners in the near term and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions to Duncan Energy Partners.

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Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2006 (dollars in thousands). For additional information regarding these significant contractual obligations, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Scheduled maturities of long-term debt	$ 5,329,068	$	$ 500,000	$1,929,068	$2,900,000
Estimated cash payments for interest	$ 5,703,440	$ 325,267	$ 613,348	$ 465,947	$4,298,878
Operating lease obligations	$ 274,700	$ 19,190	$ 36,251	$ 31,951	$ 187,308
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 920,736	$ 153,316	$ 307,052	$ 306,632	$ 153,736
NGLs	$ 2,902,805	$ 959,127	$ 436,885	$ 426,630	$1,080,163
Petrochemicals	$ 2,656,633	$1,110,957	$ 693,362	$ 339,434	$ 512,880
Other	$ 79,418	$ 35,183	$ 41,334	$ 1,424	$ 1,477
Underlying major volume commitments:					
Natural gas (in BBtus)	109,600	18,250	36,550	36,500	18,300
NGLs (in MBbls)	68,331	21,957	10,408	10,172	25,794
Petrochemicals (in MBbls)	45,535	19,250	11,749	5,694	8,842
Service payment commitments	$ 15,725	$ 10,413	$ 4,659	$ 186	$ 467
Capital expenditure commitments	$ 239,000	$ 239,000			
Other Long-Term Liabilities, as reflected in our Consolidated Balance Sheet	$ 86,121	$	$ 14,101	$ 4,004	$ 68,016
Total	$18,207,646	$2,852,453	$2,646,992	$3,505,276	$9,202,925

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.

In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays caused by the lingering effects of Hurricanes Katrina and Rita. In general, this amendment modified certain financial covenants in light of production forecasts. In addition, the amendment increased the face amount of the letters of credit required to be issued by our Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each. For more information regarding Cameron Highway s senior secured notes, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

In May 2006, Poseidon amended its revolving credit facility to, among other things, reduce commitments from $170.0 million to $150.0 million, extend the maturity date from January 2008 to May 2011 and lower the borrowing rate.

At December 31, 2006, long term debt for Evangeline consisted of (i) $18.2 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. In addition, we furnished $1.1 million in letters of credit on behalf of Evangeline at December 31, 2006.

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. See Note 14 of the Notes to the Consolidated Financial Statements included under Item 8 of this annual report for the information regarding the debt obligations of our unconsolidated affiliates.

Summary of Related Party Transactions

The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For the Year Ended December 31,		
	2006	**2005**	**2004**
Revenues from consolidated operations			
EPCO and affiliates	$ 98,671	$ 311	$ 2,697
Shell			542,912
Unconsolidated affiliates	304,559	354,461	258,541
Total	$403,230	$354,772	$804,150
Operating costs and expenses			
EPCO and affiliates	$311,537	$293,134	$203,100
Shell			725,420
Unconsolidated affiliates	31,606	23,563	37,587
Total	$343,143	$316,697	$966,107
General and administrative expenses			
EPCO and affiliates	$ 41,265	$ 40,954	$ 29,307

For additional information regarding our related party transactions, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding certain business relationships and related transactions, see 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 and affiliates 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.

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 we make to K/D/S Promix, L.L.C. for NGL transportation, storage and fractionation services.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see *Other Items Initial Public Offering of Duncan Energy Partners* within this section.

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Non-GAAP reconciliations

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):

	For the Year the Ended December 31,		
	2006	**2005**	**2004**
Total non-GAAP segment gross operating margin	$1,362,449	$1,136,347	$ 655,191
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(440,256)	(413,441)	(193,734)
Retained lease expense, net in operating costs and expenses	(2,109)	(2,112)	(7,705)
Gain on sale of assets in operating costs and expenses	3,359	4,488	15,901
General and administrative costs	(63,391)	(62,266)	(46,659)
GAAP consolidated operating income	860,052	663,016	422,994
Other net expense, primarily interest expense	(229,967)	(225,178)	(153,625)
GAAP income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles	$ 630,085	$ 437,838	$ 269,369

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the retained leases). These subleases are part of the administrative services agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. For additional information regarding the administrative services agreement and the retained leases, see Item 13 of this annual report.

Cumulative effect of changes in accounting principles

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

We recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million in 2006 based on the Statement of Financial Accounting Standards (SFAS) 123(R), *Share-Based Payment*, requirements to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards.

We recorded a $4.2 million non-cash expense related to certain asset retirement obligations in 2005 due to our implementation of FIN 47 as of December 31, 2005.

We recorded a combined $10.8 million non-cash gain in 2004 related to the impact of (i) changing the method our BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method and (ii) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

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, see Note 8 of the Notes to Consolidated

Financial Statements included under Item 8 of this annual report.

Recent Accounting Pronouncements

The accounting standard setting bodies and the SEC have recently issued the following accounting guidance that will or may affect our future financial statements:

Emerging Issues Task Force No. 06-3, *How Taxes Collected From Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*,

SFAS 155, *Accounting for Certain Hybrid Financial Instruments*,

SFAS 157, *Fair Value Measurements*, and

SFAS 159, *Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115*.

For additional information regarding these recent accounting developments and others that may affect our future financial statements, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange 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 (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) 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, see 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, interest rate or exchange 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.

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 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.

Fair value hedges Interest rate swaps

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2006 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 8.89%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.43%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.33%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.76%	$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, 2006, was a liability of $29.1 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2006, 2005 and 2004 reflects a $5.2 million loss, $10.8 million benefit and $9.1 million benefit from these swap agreements, respectively.

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.

		Swap Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2005**	**December 31, 2006**	**February 7, 2007**
FV assuming no change in underlying interest rates	*Asset (Liability)*	$(19,179)	$ (29,060)	$ (31,918)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(50,308)	(56,249)	(58,956)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	11,950	(1,872)	(4,881)

The fair value of the interest rate swaps excludes the benefit (detriment) we have already recorded in earnings. The change in fair value between December 31, 2006 and February 7, 2007 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 7, 2007 fair values ranged from approximately 4.8% to 5.4% using 6-month reset periods ranging from February 2007 to October 2014.

Cash flow hedges Treasury locks

During the second quarter of 2006, the Operating Partnership entered into a treasury lock transaction having a notional amount of $250.0 million. In addition, in July 2006, the Operating Partnership entered into an additional treasury lock transaction having a notional amount of $50.0 million. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. The Operating Partnership s purpose in entering into these transactions was to hedge the underlying U.S. treasury rate related to its anticipated issuance of subordinated debt during the second quarter of 2006. In July 2006, the Operating Partnership issued $300.0 million in principal amount of its Junior Subordinated Notes A (see Note 14 in the Notes to the Consolidated Financial Statements under Item 8). Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. In July 2006, the Operating Partnership elected to terminate these treasury lock transactions and recognized a minimal gain.

During the fourth quarter of 2006, the Operating Partnership entered into treasury lock transactions having a notional value of $562.5 million. The Operating Partnership entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of debt during 2007. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. At December 31, 2006, the value of the treasury locks was $11.2 million.

On February 27, 2007, the Operating Partnership entered into additional treasury lock transactions having a notional value of $437.5 million. The Operating Partnership entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of debt during 2007. Each of the treasury lock transactions will be designated as a cash flow hedge under SFAS 133.

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 price risks associated with such products, 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) the value of 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, NGLs or certain petrochemical products. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

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The fair value of our commodity financial instrument portfolio at December 31, 2006 was a liability of $3.2 million. During the years ended December 31, 2006, 2005 and 2004, we recorded $10.3 million, $1.1 million and $0.4 million, respectively, of income related to our commodity financial instruments, which is included in operating costs and expenses on our Statements of Consolidated Operations.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table. The following table shows the effect of hypothetical price movements on the estimated fair value (FV) of this portfolio at the dates presented (dollars in thousands):

		Commodity Financial Instrument Portfolio FV		
Scenario	Resulting Classification	December 31, 2005	December 31, 2006	February 7, 2007
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (53)	$ (3,184)	$ 549
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(53)	(2,119)	1,734
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(53)	(4,249)	(637)

Foreign Currency Hedging Program

In October 2006, we acquired all of the outstanding stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan. Since this foreign subsidiary s functional currency is the Canadian dollar, we could be adversely affected by fluctuations in foreign currency exchange rates. We attempt to hedge this risk using foreign purchase contracts to fix the exchange rate. As of December 31, 2006, we had entered into foreign purchase contracts valued at $5.1 million, all of which settled in January 2007. In January and February 2007, we entered into $3.8 million and $4.8 million, respectively, of such instruments. These contracts typically settle in the month following their inception. Due to the limited duration of these contracts, we utilize mark-to-market accounting for these transactions, the effect of which has had a minimal impact on our earnings.

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, see *Contractual Obligations* included under Item 7 of this annual report.

Item 8. *Financial Statements and Supplementary Data*.

Our consolidated financial statements, together with the independent registered public accounting firm s report of Deloitte & Touche LLP, begin on page F-1 of this report.

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, including the chief executive officer (CEO) and chief financial officer (CFO) of Enterprise Products GP, evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2006. This evaluation concluded that our disclosure controls and procedures, including internal controls over financial reporting, are effective 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. 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.

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 Enterprise Products Partners 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 assurance of achieving our desired control objectives, and our CEO and CFO have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance as of December 31, 2006.

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 Enterprise Products GP, 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 Item 308 of SEC Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management s assessment of the effectiveness of our internal controls over financial reporting, is found on page 95.

Changes in internal control over financial reporting during the fourth quarter of 2006

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the fourth quarter of 2006, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2006

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to Enterprise Products Partners management and board of directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners internal control over financial reporting as of December 31, 2006. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2006, Enterprise Products Partners internal control over financial reporting is effective based on those criteria.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein under Item 9A of this annual report.

Our Audit, Conflicts and Governance Committee is composed of directors who are not officers or employees of Enterprise Products GP. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Enterprise Products Partners internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit, Conflicts and Governance Committee all of Enterprise Products Partners significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit, Conflicts and Governance Committee without the presence of management.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 28, 2007.

/s/ Robert G. Phillips		*/s/ Michael A. Creel*	
Name:	Robert G. Phillips	Name:	Michael A. Creel
Title:	Chief Executive Officer of our general partner, Enterprise Products GP, LLC	Title:	Chief Financial Officer of our general partner, Enterprise Products GP, LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting as of December 31, 2006, that Enterprise Products Partners L.P. and its consolidated subsidiaries (Enterprise Products Partners) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Enterprise Products Partners management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of Enterprise Products Partners internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Enterprise Products Partners maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, Enterprise Products Partners maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet, the related statements of consolidated operations, consolidated comprehensive income, consolidated cash flows, consolidated partners equity and the consolidated financial statement schedule as of and for the year ended December 31, 2006 of Enterprise Products Partners and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and the financial statement schedule.

/s/ Deloitte & Touche LLP
Houston, Texas
February 28, 2007

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

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance*****.**

Partnership Management

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 (the Board) and executive officers of Enterprise Products GP, our general partner. For a description of the administrative services agreement, see *Certain Relationships and Related Transactions Relationship with EPCO* under Item 13 of this annual report.

The executive officers are elected for one-year terms and may be removed, with or without cause, only by the Board. Our 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. Each member of the Board serves until such member s death, resignation or removal. The employees of EPCO who served as directors of Enterprise Products GP during 2006 were Messrs. Duncan, Phillips, Cunningham, Creel, Bachmann and Fowler.

On February 14, 2006, Dr. Ralph S. Cunningham, Michael A. Creel, Richard H. Bachmann, W. Randall Fowler and Stephen L. Baum were elected directors of our general partner. In addition, O.S. Andras, W. Matt Ralls and Richard S. Snell resigned from the board of directors of Enterprise Products GP effective February 14, 2006. There were no disagreements between Messrs. Andras, Ralls, Snell and us on any matter relating to our operations, policies or practices which resulted in their resignation. Following such resignations, Mr. Andras and Mr. Ralls were appointed directors of the general partner of Enterprise GP Holdings L.P., which owns a 100% membership interest in Enterprise Products GP. Mr. Snell was elected a director of the general partner of an affiliate, TEPPCO Partners L.P., in January 2006.

On October 12, 2006, Charles M. Rampacek and Rex C. Ross were elected as directors, to replace Stephen L. Baum and Philip C. Jackson, who resigned on October 10, 2006 and October 12, 2006, respectively. There were no disagreements between Messrs. Jackson, Baum and us on any matter relating to our operations, policies or practices which resulted in their resignation.

In November 2006, the Board approved the merging of its Audit and Conflicts Committee with its Governance Committee, resulting in a combined committee entitled the Audit, Conflicts and Governance Committee (ACG Committee). Unless the context requires otherwise, references to ACG Committee include references to the separate Audit and Conflicts Committee and Governance Committee.

During 2006, there were seven meetings of the Board. In addition, the ACG Committee met eleven times regarding audit and conflicts matters and four times regarding governance matters. Messrs. Cunningham and Bachmann attended four and five of the Board meetings, respectively, during 2006. For their respective periods of service, the remaining directors were present at each Board meeting.

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 Enterprise Products GP 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 Enterprise Products GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise Products GP 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 Enterprise Products GP. Whenever possible, Enterprise Products GP intends to make any such indebtedness or other obligations non-recourse to itself.

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.

Corporate Governance

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.

A key element for strong governance is independent members of the Board. 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 Enterprise Products GP 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 Rex C. Ross, Charles M. Rampacek and E. William Barnett are independent directors under the NYSE rules.

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 its audit committee members do not satisfy a heightened independence standard. In order to meet this standard, members of such audit committees 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 Enterprise Products GP nor any individual member of its ACG Committee has relied on any exemption in the NYSE rules to establish such individual s independence. Based on the foregoing criteria, the Board has affirmatively determined that all members of its ACG Committee satisfy this heightened independence requirement.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise Products GP 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.

In addition, Enterprise Products GP has adopted a code of ethics, the *Code of Ethical Conduct for Senior Financial Officers and Managers*, that applies to the chief executive officer, chief financial officer, 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.

Governance guidelines, together with applicable committee charters, provide the framework for effective governance. The Board has adopted the *Governance Guidelines of Enterprise Products Partners*, which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of the ACG Committee, 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 recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary or appropriate.

We provide access through our website at www.epplp.com to current information relating to governance, including the Code of Ethical Conduct for Senior Financial Officers and Managers, the Governance Guidelines of Enterprise Products Partners and other matters impacting our governance principles. You may also contact our investor relations department at (713) 381-6521 for printed copies of these documents free of charge.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named three of its members to serve on the ACG Committee. The members of the ACG Committee are independent directors free from any relationship with us or any of our affiliates or subsidiaries that would interfere with the exercise of independent judgment.

The members of the ACG 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 ACG Committee shall have accounting or related financial management expertise. At December 31, 2006, the members of the ACG Committee are Rex C. Ross, Charles M. Rampacek and E. William Barnett, who is chairman of the ACG Committee. Our Board has determined that Mr. Rampacek qualifies as an independent audit committee financial expert as defined in Item 401(h) of Regulation S-K promulgated by the SEC.

The ACG Committee s duties are addressing audit and conflicts-related items and general corporate governance. From an audit and conflicts standpoint, the primary responsibilities of the ACG 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 Enterprise Products GP;

§ 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;

§ 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 1998 Long-Term Incentive Plan.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the ACG Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the ACG Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by Enterprise Products GP or the Board of any duties it may owe us or our unitholders.

Pursuant to its formal written charter, as amended and currently in effect, the ACG 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 ACG 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.

From a governance standpoint, the primary responsibilities of the ACG Committee 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. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our website, www.epplp.com. You may also contact our investor relations department at (713) 381-6521 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

Annual CEO Certification. On April 5, 2006, our chief executive officer certified to the NYSE, as required by Section 303A.12(a) of the NYSE Listed Company Manual, that as of April 5, 2006, he was not aware of any violation by us of the NYSE s Corporate Governance listing standards.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors 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 Mr. Barnett.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the Hotline) so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the ACG Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

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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 Enterprise Products GP at February 28, 2007. Each executive officer holds the same respective office shown below in the general partner of the Operating Partnership.

Name	Age	Position with Enterprise Products GP
Dan L. Duncan [1]	74	Director and Chairman
Robert G. Phillips[1]	52	Director, President and Chief Executive Officer
Dr. Ralph S. Cunningham [1]	66	Director, Group Executive Vice President and Chief Operating Officer
Michael A. Creel [1]	53	Director, Executive Vice President and Chief Financial Officer
Richard H. Bachmann [1]	54	Director, Executive Vice President, Chief Legal Officer and Secretary
W. Randall Fowler [1]	50	Director, Senior Vice President and Treasurer
E. William Barnett [2,3]	74	Director
Rex C. Ross [2]	63	Director
Charles M. Rampacek [2]	63	Director
James H. Lytal [1]	49	Executive Vice President
A.J. Teague [1]	61	Executive Vice President
Gil H. Radtke	46	Senior Vice President
James M. Collingsworth	52	Senior Vice President
Michael J. Knesek [1]	52	Senior Vice President, Controller and Principal Accounting Officer

(1) Executive officer

(2) Member of ACG Committee

(3) Chairman of ACG Committee

Dan L. Duncan was elected chairman and a director of Enterprise Products GP in April 1998 and chairman and a director of the general partner of our Operating Partnership in December 2003. Mr. Duncan has served as chairman and a director of EPE Holdings since April 2005 and as chairman of EPCO since 1979. Mr. Duncan was elected chairman and director of the general partner of Duncan Energy Partners in October 2006.

Robert G. Phillips was elected 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; a director of the general partner of our Operating Partnership since September 2004; and a director of EPE Holdings since February 2006.

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.

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 the general partner of TEPPCO 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.

Dr. Cunningham 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). He was a director of EPCO from 1987 to 1997.

Michael A. Creel was elected an 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 our Operating Partnership since December 2003, and has served as president, chief executive officer and a director of EPE Holdings since August 2005.

Mr. Creel was elected a director of Edge Petroleum Corporation (a publicly traded oil and natural gas exploration and production company) in October 2005 and a director of Enterprise Products GP in February 2006. In October 2006, Mr. Creel was elected executive vice president, chief financial officer and a director of the general partner of Duncan Energy Partners.

Richard H. Bachmann was elected an executive vice president, chief legal officer and secretary of Enterprise Products GP and EPCO in January 1999 and a director of Enterprise Products GP in February 2006. Mr. Bachmann previously served as a director of Enterprise Products GP from June 2000 to January 2004. Mr. Bachmann has served as a director of the general partner of our Operating Partnership since December 2003 and has served as executive vice president, chief legal officer and secretary of EPE Holdings since August 2005.

Mr. Bachmann was elected a director of EPE Holdings in February 2006 and of EPCO in January 1999. In October 2006, Mr. Bachmann was elected president, chief executive officer and a director of the general partner of Duncan Energy Partners. In November 2006, Mr. Bachmann was appointed an independent manager of Constellation Energy Partners LLC. Mr. Bachmann serves as a member of the audit, compensation and nominating and governance committee of Constellation Energy Partners LLC.

W. Randall Fowler was elected senior vice president and treasurer of Enterprise Products GP in February 2005 and a director in February 2006. 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. Mr. Fowler has served as senior vice president and chief financial officer of EPE Holdings since August 2005 and as chief financial officer of EPCO since April 2005.

Mr. Fowler was elected a director of EPE Holdings in February 2006. In October 2006, Mr. Fowler was elected a senior vice president, treasurer and a director of the general partner of Duncan Energy Partners.

E. William Barnett was elected a director of Enterprise Products GP in March 2005. Mr. Barnett is a member of our ACG Committee and serves as its chairman. 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.

Mr. Barnett 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 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) and Westlake Chemical Corporation (a publicly traded chemical company). He is also director and former chairman of the Greater Houston Partnership. He is 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.

Rex C. Ross was elected a director of Enterprise Products GP in October 2006 and is a member of its ACG Committee. Mr. Ross serves as a non-executive chairman of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the United States. Prior to his executive retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including president of Schlumberger Oilfield Services North America; president, Schlumberger GeoQuest; and president of SchlumbergerSema North & South America.

Charles M. Rampacek was elected a director of Enterprise Products GP in October 2006 and is a member of its ACG Committee. Mr. Rampacek is currently a business and management consultant in the energy industry. Mr. Rampacek served as chairman, chief executive officer and president of Probex Corporation (Probex), an energy technology company that developed a proprietary used oil recovery process, from 2000 until his retirement in 2003. Prior to joining Probex Corporation, Mr. Rampacek was president and chief executive officer of Lyondell-Citgo Refining L.P, a manufacturer of petroleum products, from January 1996 through August 2000. From 1982 to 1995, he held various executive positions with Tenneco Inc. and its energy related subsidiaries, including president of Tenneco Gas Transportation Company, executive vice president of Tenneco Gas Operations and senior vice president of Refining.

His extensive management background in the energy transportation and refining sectors also includes 13 years with Tenneco, Inc. and its energy-related subsidiaries, serving as president of Gas Pipeline Transportation and senior vice president of Refining and Supply. In addition, Mr. Rampacek spent 16 years with Exxon Company USA, where he served as planning manager of Refining, planning manager of Coal and Synthetic Fuels, as well as operations and technical manager of the Benicia, California refinery. Mr. Rampacek has been a director of Flowserve Corporation since 1998 and is chairman of its Corporate Governance and Nominating Committee and a member of its Audit Committee.

In 2005, two complaints requesting recovery of certain costs were filed against former officers and directors of Probex Corporation as a result of the bankruptcy of Probex in 2003. These complaints were defended under Probex s director and officer insurance by AIG and settlement was reached and paid by AIG with bankruptcy court approval in the first half of 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt of which Mr. Rampacek was one. A settlement of $2,000 was reached and approved by the bankruptcy court in the first half of 2006.

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.

Gil H. Radtke was elected a senior vice president of Enterprise GP in February 2002. Mr. Radtke joined us in connection with our purchase of Diamond-Koch s storage and propylene fractionation assets in January and February 2002. Before joining us, Mr. Radtke served as president of the Diamond-Koch joint venture from 1999 to 2002, where he was responsible for its storage, propylene fractionation, pipeline and NGL fractionation businesses. From 1997 to 1999 he was vice president, Petrochemicals and Storage of Diamond-Koch. In October 2006, Mr. Radtke was elected senior vice president, chief operating officer and a director of the general partner of Duncan Energy Partners.

James M. Collingsworth joined Enterprise GP as a Vice President in November 2001 and was elected a Senior Vice President in November 2002. Previously, he served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001.

Michael J. Knesek, a certified public accountant, was elected senior vice president and principal accounting officer 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 served as senior vice president and principal accounting officer of EPE Holdings since August 2005. In October 2006, Mr. Knesek was elected senior vice president, principal accounting officer and controller of the general partner of Duncan Energy Partners. Mr. Knesek has been the controller and a vice president of EPCO since 1990.

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, Enterprise Products GP, directors of Enterprise Products GP, executives (and certain other) officers, and any persons holding more than 10% of our common units are required to report their ownership of common 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 2006. Dan L. Duncan filed two late reports during 2006 in connection with the exercise of options by employees of EPCO.

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Item 11. *Executive Compensation*.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing or operating our business and we have no compensation committee. Instead, 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, and is generally based on time allocated during a period to the activities of EPCO or the EPCO affiliates who reimburse EPCO pursuant to this agreement. For a description of the administrative services agreement, see *Relationship with EPCO and affiliates Administrative Services Agreement* under Item 13 of this annual report.

Summary Compensation Table

The following table presents consolidated compensation amounts paid, accrued or otherwise expensed by us with respect to the year ended December 31, 2006 to our general partner s chief executive officer, chief financial officer and our three other most highly compensated executive officers at December 31, 2006 (collectively, the named executive officers).

Name and Principal Position	Year	Salary ($)	Bonus ($) (2)	Unit Awards ($) (3)	Option Awards ($) (4)	All Other Compensation ($) (5)	Total ($)
Enterprise Products GP:							
Robert G. Phillips, CEO	2006	$722,500	$300,000	$660,270	$357,209	$150,984	$2,190,962
Michael A. Creel, CFO (1)	2006	$306,000	$125,000	$303,622	$ 23,613	$ 71,812	$ 830,048
James H. Lytal	2006	$367,500	$187,500	$455,462	$ 47,227	$101,639	$1,159,327
A.J. Teague	2006	$428,480	$250,000	$299,984	$ 47,227	$ 69,563	$1,095,254
Ralph S. Cunningham	2006	$478,667	$250,000	$ 52,815	$ 13,707	$ 33,208	$ 828,397

(1) Amounts presented reflect compensation allocated to us based on the percentage of time Mr. Creel spent on our consolidated business activities during 2006.

(2) Amounts represent discretionary annual cash awards accrued for the year

ended December 31, 2006. Payment of these amounts was made in February 2007.

(3) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to restricted unit and Employee Partnership awards for the year ended December 31, 2006.

(4) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to unit option awards for the year ended December 31, 2006.

(5) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions received from restricted unit

awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.

Compensation Discussion and Analysis

Compensation paid or awarded by us in 2006 with respect to our named executive officers reflects only that portion of compensation paid by EPCO allocated to us pursuant to the administrative services agreement, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to compensation of our named executive officers. The following elements of compensation, and EPCO s decisions with respect to determination of payments, are not subject to approvals by our Board or the ACG Committee. Awards under EPCO s long-term incentive plans are approved by the ACG Committee. We do not have a separate compensation committee (see Item 10 of this annual report).

As discussed below, the elements of EPCO s compensation program, along with EPCO s other rewards (e.g., benefits, work environment, career development), are intended to provide a total rewards package to employees. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels. During 2006, EPCO s compensation package did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO s compensation program are a combination of annual cash and long-term equity-based incentive compensation. During 2006, the elements of compensation for the named executive officers consisted of the following:

§ Annual base salary;

§ Discretionary annual cash awards;

§ Awards under long-term incentive arrangements; and

§ Other compensation, including very limited perquisites.

With respect to compensation objectives and decisions regarding the named executive officers for 2006, Mr. Duncan sought and received recommendations of Robert G. Phillips, the chief executive officer of Enterprise Products GP, after preliminary formulation of such recommendation by him and the senior vice president of Human Resources for EPCO with respect to employees other than Mr. Phillips. EPCO takes note of market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, various relevant compensation surveys. EPCO considered market data in a 2004-2005 survey prepared for EPCO by an outside compensation consultant, but did not otherwise consult with compensation consultants with respect to determining 2006 compensation for the named executive officers.

During late 2006, EPCO engaged an outside compensation consultant to prepare a report that it expects to consider when determining future compensation, but EPCO did not use this report in making decisions on discretionary annual cash compensation with respect to 2006 for any of our named executive officers. Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our named executive officers in connection with services performed for us. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan s ultimate decision-making authority.

The discretionary cash awards paid to each of our named executive officers for the year ended December 31, 2006 were determined by consultation among Mr. Duncan, Mr. Phillips and the senior vice president of Human Resources for EPCO, subject to Mr. Duncan s final determination. These cash awards, in combination with base salaries, are intended to yield competitive total cash compensation levels for the executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officers perform services. The portion of any discretionary cash awards paid by EPCO allocable to us and reported as compensation to our named executive officers were based on the provisions of the administrative services agreement. It is EPCO s general policy to pay these awards during the first quarter of each year.

The 2006 equity awards granted to our named executive officers were determined by consultation among Mr. Duncan, Mr. Phillips and the senior vice president of Human Resources for EPCO, and were approved by the ACG Committee. These awards (restricted units and unit options) are intended to align the long-term interests of the executive officers with those of our unitholders. It is EPCO s general policy to recommend, and the ACG Committee typically approves, these grants to employees during the second quarter of each fiscal year. Individually, our named executive officers are Class B limited partners in either EPE Unit I or EPE Unit II. See *Summary of Long-Term Incentive Arrangements* within this Item 11. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our accounting for equity awards.

EPCO generally does not pay for perquisites for any of our named executive officers, other than reimbursement of certain parking expenses, and expects to continue its policy of covering very limited

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perquisites allocable to our named executive officers. EPCO also makes matching contributions under its 401(k) plan for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during 2006.

We believe that each of the base salary, cash awards, and equity awards fit the overall compensation objectives of us and of EPCO, as stated above (i.e., to provide competitive compensation opportunities to align and drive employee performance toward the creation of sustained long-term unitholder value, which will also allow us to attract, motivate and retain high quality talent with the skills and competencies required by us).

Grants of Plan-Based Awards in Fiscal Year 2006

The following table presents information concerning each grant of an equity award made to a named executive officer in 2006. All equity awards granted during 2006 were under EPCO s 1998 Long-Term Incentive Plan (the 1998 Plan). See *Summary of Long-Term Incentive Arrangements* within this Item 11.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted unit awards:						
Robert G. Phillips	5/1/2006		24,000			$549,881
Michael A. Creel	5/1/2006		12,000			$151,217
James H. Lytal	5/1/2006		12,000			$274,940
A. J. Teague	5/1/2006		12,000			$274,940
Ralph S. Cunningham	5/1/2006		12,000			$274,940
Unit option awards:						
Robert G. Phillips	5/1/2006		80,000		$24.85	$164,483
Michael A. Creel	5/1/2006		40,000		$24.85	$ 41,121
James H. Lytal	5/1/2006		40,000		$24.85	$ 82,241
A. J. Teague	5/1/2006		40,000		$24.85	$ 82,241
Ralph S. Cunningham	5/1/2006		40,000		$24.85	$ 82,241
EPE Unit II profits interest award:						
Ralph S. Cunningham	12/5/2006					$212,289

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the percentage of time each officer spent on our consolidated business activities during

2006. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will equal these amounts over time. For the period in which these awards were outstanding during 2006, we recognized a total of $317 thousand of consolidated compensation expense for these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

The fair value amounts shown in the preceding table are based on certain assumptions and considerations made by management. The grant date fair values of restricted unit awards issued in May 2006 were based on a market price of $24.85 per unit and an assumed forfeiture rate of 7.8%.

The grant date fair values of unit option awards issued in May 2006 were based on the following assumptions: (i) expected life of the options of seven years; (ii) risk-free interest rate of 5.0%; (iii) an expected distribution yield on our units of 8.9%; and (iv) an expected unit price volatility of our units of 23.5%.

The fair value of the EPE Unit II profits interest award issued in December 2006 was based on the following assumptions: (i) remaining life of the award of five years; (ii) risk-free interest rate of 4.4%; (iii) an expected distribution yield on Enterprise GP Holdings units of 3.8%; and (iv) an expected unit price volatility of Enterprise GP Holdings units of 18.7%. The EPE Unit II profits interest awards are classified as liability awards under the provisions of SFAS 123(R).

Outstanding Equity Awards at 2006 Fiscal Year-End

The following table presents information concerning each named executive officer s unexercised unit options and restricted units that have not vested as of December 31, 2006.

	Option Awards			Unit Awards	
Name	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)
Robert G. Phillips					
September 30, 2004 option award (4)	500,000	$23.18	9/30/2014		
August 4, 2005 option award (2)	70,000	$26.47	8/4/2015		
May 1, 2006 option award (3)	80,000	$24.85	5/1/2016		
Restricted unit awards (5)				86,553	$2,508,306
Employee Partnership award (6)				28,098	$1,038,794
Michael A. Creel :					
May 10, 2004 option award (1)	35,000	$20.00	5/10/2014		
August 4, 2005 option award (2)	35,000	$26.47	8/4/2015		
May 1, 2006 option award (3)	40,000	$24.85	5/1/2016		
Restricted unit awards (5)				76,553	$2,218,506
Employee Partnership award (6)				28,098	$1,038,794
James H. Lytal:					
September 30, 2004 option award (4)	35,000	$23.18	9/30/2014		
August 4, 2005 option award (2)	35,000	$26.47	8/4/2015		
May 1, 2006 option award (3)	40,000	$24.85	5/1/2016		
Restricted unit awards (5)				59,532	$1,725,237
Employee Partnership award (6)				18,872	$ 697,693
A.J. Teague:					
May 10, 2004 option award (1)	35,000	$20.00	5/10/2014		
August 4, 2005 option award (2)	35,000	$26.47	8/4/2015		
May 1, 2006 option award (3)	40,000	$24.85	5/1/2016		
Restricted unit awards (5)				34,000	$ 985,320
Employee Partnership award (6)				18,872	$ 697,693
Ralph S. Cunningham					
May 1, 2006 option award (3)	40,000	$24.85	5/1/2016		
Restricted unit awards (5)				12,000	$ 347,760
Employee Partnership award (7)				152	$ 5,603

(1)

These awards vest on May 10, 2008.

(2) These awards vest on August 4, 2009.

(3) These awards vest on May 1, 2010.

(4) This award vests on September 30, 2008.

(5) The total number of nonvested restricted units held by our named executive officers at December 31, 2006 was 268,638. Of this amount, 24,000 vest on May 28, 2008, 12,000 vest on September 30, 2008, 110,638 vest on October 12, 2008, 50,000 vest on August 4, 2009 and 72,000 vest on May 1, 2010. The estimated market value of these nonvested restricted units is based on a closing price of $28.98 per unit on December 29, 2006.

(6) The EPE Unit I profits interests awards vest on August 30, 2010. See *Summary of Long-Term Incentive Arrangements Employee Partnership awards* for additional information regarding these awards.

(7) This EPE Unit II profits interest award vests on December 5, 2011. See *Summary of Long-Term Incentive Arrangements Employee Partnership awards* for additional information regarding these awards.

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Summary of Long-Term Incentive Arrangements

Restricted unit awards. Under the 1998 Plan, we may issue restricted common units to key employees of EPCO and directors of our general partner. The 1998 Plan provides for the issuance of 3,000,000 restricted common units, of which 1,737,364 remain authorized for issuance at December 31, 2006. In general, restricted unit awards allow recipients to acquire the underlying common units (at no cost to the recipient) once a defined vesting period expires, subject to certain forfeiture provisions. The restrictions on such nonvested units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. The fair value of restricted units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures.

Unit option awards. Under EPCO s 1998 Plan, non-qualified, incentive options to purchase a fixed number of our common units may be granted to EPCO s key employees who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant. In order to fund its obligations under the 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. 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.

Employee Partnership awards. In connection with Enterprise GP Holdings initial public offering in August 2005, EPCO formed EPE Unit I to serve as an incentive arrangement for certain employees of EPCO through a profits interest in EPE Unit I. In December 2006, EPE Unit II was formed to serve as an incentive arrangement for Dr. Cunningham, who is not a participant in the EPE Unit I arrangement. These awards are designed to provide additional long-term incentive compensation for our named executive officers. The profits interest awards (or Class B limited partner interests) in EPE Unit I or EPE Unit II entitle the holder to participate in the appreciation in value of the parent company s units and are subject to forfeiture.

At December 31, 2006, four of our named executive officers held Class B limited partner interests in EPE Unit I as follows: Robert G. Phillips, 7.2%, Michael A. Creel, 7.2%, James H. Lytal, 4.8% and A.J. Teague, 4.8%. Based on a closing market price of the parent company s units of $36.97 per unit at December 29, 2006 and taking into account the terms of liquidation outlined in the EPE Unit I partnership agreement, we estimate that the total profits interests would have been worth $14.4 million, of which each named executive officer would have received his proportionate share. See *Relationship with EPCO and its other affiliates* *Relationship with Employee Partnerships* under Item 13 for additional information regarding EPE Unit I.

At December 31, 2006, Dr. Cunningham was the sole Class B limited partner in EPE Unit II. Based on a closing market price of the parent company s units of $36.97 per unit at December 29, 2006 and taking into account the terms of liquidation outlined in the EPE Unit II partnership agreement, we estimate that the total profits interests would have been worth a nominal amount. See *Relationship with EPCO and its other affiliates* *Relationship with Employee Partnerships* under Item 13 for additional information regarding EPE Unit II.

Option Exercises and Stock Vested Table

The named executive officers did not exercise any unit options during the year ended December 31, 2006. In addition, the named executive officers did not become vested in any equity-based awards during the year.

Director Compensation

The following table presents information regarding compensation to the independent directors of our general partner during 2006.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	Option Awards ($) (3)	All other Compensation ($) (7)	Total ($)
Current directors:					
E. William Barnett	$32,500	$ 8,936(1)	$9,159(4)	$ 2,244	$52,839
Rex C. Ross	$ 6,250		$6,759(5)	$	$13,009
Charles M. Rampacek	$ 6,250		$6,759(6)	$	$13,009
Former directors:					
Philip C. Jackson	$24,435	$36,336(2)		$ 1,016	$61,787
Stephen L. Baum	$19,565	$25,785(2)		$ 449	$45,799
W. Matt Ralls	$ 3,972	$25,603(2)		$ 532	$30,108

(1) Mr. Barnett holds 1,744 of our nonvested restricted units. Of this amount, 269 units vest on May 24, 2009, 475 units vest on August 4, 2009, 500 units vest on February 21, 2010 and 500 units vest on August 2, 2010. At December 31, 2006, the total market value of these units was $51 thousand based on a closing market price of $28.98 per common unit at December 29, 2006. The dollar amount presented under the column labeled Unit Awards for Mr. Barnett represents the

expense recognized by Enterprise Products GP during 2006 related to these awards attributable to his service during 2006.

(2) The restricted units held by these former directors vested upon their respective resignation dates (see Item 10) and converted to common units on a one-for-one basis. The dollar amounts presented under the column labeled Unit Awards for Messrs. Jackson, Baum and Ralls represent the expense recognized by Enterprise Products GP during 2006 related to these awards, including the acceleration of expense amounts due to each director s resignation.

(3) Amount presented reflects the compensation expense recognized by Enterprise

Products GP related to unit appreciation rights granted during 2006 under letter agreements.

(4) At December 31, 2006, the fair value of UARs granted to Mr. Barnett was $195 thousand.

(5) At December 31, 2006, the fair value of UARs granted to Mr. Ross was $202 thousand.

(6) At December 31, 2006, the fair value of UARs granted to Mr. Rampacek was $202 thousand.

(7) Amounts primarily represent quarterly distributions received from restricted unit awards.

Neither we nor Enterprise Products GP 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 Enterprise Products GP during 2006 were Messrs. Duncan, Phillips, Cunningham, Creel, Bachmann and Fowler.

Independent Director Compensation

At February 27, 2007, our independent directors are Messrs. Barnett, Ross and Rampacek. Enterprise Products GP is responsible for compensating these directors for their services.

Cash Compensation. For the year ended December 31, 2006, our standard compensation arrangement for independent directors was as follows: (i) each director received $25,000 in cash and $25,000 worth of restricted common units annually and (ii) if the individual served as chairman of a committee of the Board, he received an additional $7,500 in cash annually. Effective January 1, 2007, our standard cash compensation arrangement was changed to reflect the following:

§ Each independent director receives $50,000 in cash and $25,000 worth of restricted units annually.

§ If the individual serves as chairman of a committee of the Board, then he receives an additional $15,000 in cash annually.

Equity-Based Compensation. The independent directors of our general partner have been granted unit appreciation rights (UARs). These awards are in the form of letter agreements with each of the directors and are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings or Enterprise Products Partners. The awards are based upon an incentive plan of EPE Holdings and are made in the form of UAR grants for non-employee directors of Enterprise Products GP (filed as an exhibit to this annual report on Form 10-K). The compensation expense associated with these awards is recognized by Enterprise Products GP. These UARs entitle the directors to receive a cash amount in the future equal to the excess, if any, of the fair market value of Enterprise GP Holdings units (determined as of a future vesting date) over the grant date price. If the director resigns prior to vesting, his UAR awards are forfeited.

On August 3, 2006, Messrs. Barnett, Jackson and Baum were each granted 10,000 UARs, for a total of 30,000 UARs, of which 20,000 were subsequently forfeited with Mr. Jackson and Mr. Baum resigned. The grant date price of the August 2006 UARs was $35.71 per unit. This price differs from the $35.40 per unit closing unit price of Enterprise GP Holdings units on August 3, 2006. The higher grant date price was determined by reference to the closing price of Enterprise GP Holdings units on May 2, 2006, which was the original date that these awards were contemplated to be issued. The remaining 10,000 UARs held by Mr. Barnett vest on August 3, 2011.

On November 1, 2006, Mr. Barnett was issued an additional 20,000 UARs and Messrs. Ross and Rampacek were issued 30,000 UARs each under this letter agreement format. The grant date price of these rights was $34.10 per unit. These awards vest on November 1, 2011.

These UARs are accounted for as liability awards under SFAS 123(R) since they will be settled with cash.

At December 31, 2006, the total fair value of the remaining 10,000 UARs issued in August 2006 was $60 thousand, which was based on the following assumptions: (i) remaining life of award of 4.6 years; (ii) risk-free interest rate of 4.7%; (iii) an expected distribution yield on the parent company s units of 3.8%; and (iv) an expected unit price volatility of the parent company s units of 18.7%.

At December 31, 2006, the total fair value of the 80,000 UARs issued in November 2006 was $539 thousand, which was based on the following assumptions: (i) remaining life of award of 4.8 years; (ii) risk-free interest rate of 4.7%; (iii) an expected distribution yield on the parent company s units of 3.8%; and (iv) an expected unit price volatility of the parent company s units of 18.7%.

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

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 1, 2007, regarding each person known by our general partner to beneficially own more than 5% of our common units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Dan L. Duncan 1100 Louisiana Street, 10th Floor Houston, Texas 77002	147,007,446(1)	34.0%

(1) For a detailed listing of ownership amounts that comprise Mr. Duncan s total beneficial ownership of our common units, see the table presented in the following section, *Security Ownership of Management*, within this Item 12.

Security Ownership of Management

Enterprise Products Partners L.P. and Enterprise GP Holdings L.P.

The following table sets forth certain information regarding the beneficial ownership of our common units and the units of Enterprise GP Holdings L.P. as of February 1, 2007 by:

§ each of our named executive officers;

§ all of the current directors of Enterprise Products GP; and

§ all of the current directors and executive officers of Enterprise Products GP as a group.

Enterprise GP Holdings owns 100% of the membership interests of Enterprise Products GP.

All information with respect to beneficial ownership has been furnished by the respective directors or officers. Each person has sole voting and dispositive power over the securities shown unless otherwise indicated below. The beneficial ownership amounts of certain individuals include options to acquire our common units that are exercisable within 60 days of the filing date of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to our common units beneficially owned by EPCO and its affiliates. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of members of Mr. Duncan s family. The address of

EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

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Name of Beneficial Owner	Enterprise Products Partners Amount and Nature Of Beneficial Ownership	Enterprise Products Partners Percent of Class	Enterprise GP Holdings Amount and Nature Of Beneficial Ownership	Enterprise GP Holdings Percent of Class
	Limited Partner Ownership Interests In			
Dan L. Duncan:				
Units owned by EPCO:				
Through DFI Delaware Holdings, L.P.	120,044,779	27.8%		
Through Duncan Family Interests, Inc.			71,271,231	80.2%
Through Enterprise GP Holdings L.P.	13,454,498	3.1%		
EPCO (direct)	41,500	*		
Units owned by Dan Duncan LLC (1)			3,726,273	4.2%
Units owned by EPE Unit I (2)			1,821,428	2.1%
Units owned by EPE Unit II (2)			40,725	*
Units owned by trusts (3)	12,566,645	2.9%	243,071	*
Units owned directly	900,024	*		
Total for Dan L. Duncan	147,007,446	34.0%	77,102,728	86.8%
Robert G. Phillips (4,5)	130,702	*	75,000	*
Dr. Ralph S. Cunningham (4)	16,139	*		*
Michael A. Creel (4)	114,828	*	35,000	*
Richard H. Bachmann	116,252	*	20,469	*
W. Randall Fowler	60,057	*	3,000	*
E. William Barnett	1,744	*	10,000	*
Charles M. Rampacek				
Rex C. Ross	16,170	*	4,400	*
A. J. Teague (4)	164,547	*	17,000	*
James H. Lytal (4)	76,825	*	5,000	*
All current directors and executive officers of Enterprise Products GP, as a group, (14 individuals in total) (6)	147,814,495	34.2%	77,306,597	87.0%

* *The beneficial ownership of each individual is less than 1% of the registrant s common units outstanding.*

(1) Dan Duncan LLC is owned by Mr. Duncan.

(2) As a result of EPCO s ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the units held by these entities.

(3) In addition to the units owned by EPCO, Mr. Duncan is deemed to be the beneficial owner of the common units owned by the Duncan Family 1998 Trust and the Duncan Family 2000 Trust, the beneficiaries of which are the shareholders of EPCO.

(4) These individuals are our named executive officers for 2006.

(5) The number of Enterprise Products Partners common units shown for Mr. Phllips includes 5,132 common units held by trusts for which he has disclaimed

beneficial ownership.

(6) Cumulatively, this group s beneficial ownership amount includes 10,000 options to acquire Enterprise Products Partners common units that were issued under the 1998 Plan. These options are exercisable within 60 days of the filing date of this report.

Essentially all of the ownership interests in us and Enterprise GP Holdings that are owned or controlled by EPCO are pledged as security under the credit facility of an EPCO affiliate. This credit facility contains customary and other events of default relating to EPCO and certain of its affiliates, including Enterprise GP Holdings, TEPPCO and us. In the event of a default under this credit facility, a change in control of Enterprise GP Holdings or us could occur, including a change in control of our respective general partners.

Duncan Energy Partners L.P.

On February 5, 2007, a consolidated subsidiary of Enterprise Products Partners, Duncan Energy Partners, completed its initial public offering of 14,950,000 common units. Certain of our directors and executive officers purchased common units of Duncan Energy Partners in this offering. There are 20,321,571 common units of Duncan Energy Partners outstanding following the offering. For information regarding the initial public offering of Duncan Energy Partners, see *Recent Developments* under Item 1 of this annual report.

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The following table presents the beneficial ownership of common units of Duncan Energy Partners by our directors, named executive officers and all directors and officers of our general partner (as a group) at February 5, 2007.

Name of Beneficial Owner	Duncan Energy Partners Amount And Nature Of Beneficial Ownership	Percent of Class
Dan L. Duncan, through the Operating Partnership (1)	5,371,571	26.4%
Richard H. Bachmann (2)	10,000	*
Michael A. Creel (3)	7,500	*
W. Randall Fowler	2,000	*
Robert G. Phillips	7,500	*
Dr. Ralph S. Cunningham	3,000	*
Rex C. Ross	5,000	*
All current directors and executive officers of Enterprise Products GP, as a group (14 individuals in total)	5,419,171	26.6%

* *The beneficial ownership of each individual is less than 1% of the registrant s units outstanding.*

(1) The number of common units shown for Dan L. Duncan represents the final amount of common units issued to the Operating Partnership of Enterprise Products Partners in connection with its contribution of equity interests to Duncan Energy Partners on February 5,

2007.

(2) Mr. Bachmann is the chief executive officer of Duncan Energy Partners.

(3) Mr. Creel is the chief financial officer of Duncan Energy Partners.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2006 regarding the 1998 Plan, under which our common units are authorized for issuance to EPCO s key employees and to directors of Enterprise Products GP through the exercise of unit options.

Plan Category	**Number of units to be issued upon exercise of outstanding common unit options (a)**	**Weighted-average exercise price of outstanding common unit options (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:			
1998 Plan	2,416,000(1)	$ 23.32	2,025,443
Equity compensation plans not approved by unitholders:			
None			
Total for equity compensation plans	2,416,000(1)	$ 23.32	2,025,443

(1) Of the 2,416,000 unit options outstanding at December 31, 2006, 591,000 were immediately exercisable and

an additional 785,000, 450,000, and 590,000 options are exercisable in 2008, 2009 and 2010, 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 restricted common units, of which 1,105,237 were outstanding at December 31, 2006. During 2006, a total of 466,400 restricted unit awards were issued to key employees of EPCO and our independent directors. For additional information regarding the 1998 Plan and related equity awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The following information summarizes our business relationships and related transactions with entities controlled by Dan L. Duncan during 2006. We have also provided information regarding our business relationships and transactions with our unconsolidated affiliates and Shell.

For additional information regarding our transactions with related parties, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities:

§ EPCO and its private company subsidiaries;

§ Enterprise Products GP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ Duncan Energy Partners, which is a public company subsidiary of ours;

§ TEPPCO and TEPPCO GP, which are controlled by affiliates of EPCO; and

§ the Employee Partnerships.

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.

EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP, our general partner. At December 31, 2006, EPCO and its affiliates beneficially owned 146,768,946 (or 33.9%) of our outstanding common units, which includes 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2006, EPCO and its affiliates beneficially owned 86.7% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of Enterprise Products GP. The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and EPE Holdings are employees of EPCO.

In connection with its general partner interest in us, Enterprise Products GP received cash distributions of $126.0 million, $76.8 million and $40.4 million from us during the years ended December 31, 2006, 2005 and 2004, respectively. These amounts include incentive distributions of $86.7 million, $63.9 million and $32.4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

We and Enterprise Products GP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries and affiliates depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its affiliates received $306.5 million, $243.9 million and $189.8 million in cash distributions from us during the years ended December 31, 2006, 2005 and 2004, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO.

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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. For the years ended December 31, 2006, 2005 and 2004, we paid this trucking affiliate $20.7 million, $17.6 million and $14.2 million, respectively, for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the years ended December 31, 2006, 2005 and 2004, we paid EPCO $3.0 million, $2.7 million and $1.7 million, respectively, for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition. For the years ended December 31, 2005 and 2004, our revenues from this former affiliate were $0.3 million and $2.7 million, respectively, and our purchases were $61.0 million and $71.8 million, respectively. For the nine months ended September 30, 2006, our revenues from this former affiliate were $55.8 million and our purchases were $43.4 million.

Relationship with Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.3 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to Enterprise Products Partners (along with $198.9 million in borrowings under its credit facility and a final amount of 5,371,571 common units of Duncan Energy Partners). Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,371,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under the Operating Partnership s Multi-Year Revolving Credit Facility.

In addition to the 34% direct ownership interest we retained in certain subsidiaries of Duncan Energy Partners, we also own the 2% general partner interest in Duncan Energy Partners and 26.2% of Duncan Energy Partners outstanding common units. Our Operating Partnership directs the business operations of Duncan Energy Partners through its control of the general partner of Duncan Energy Partners. Certain of our officers and directors are also beneficial owners of common units of Duncan Energy Partners (see Item 12).

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions: (i) we utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses; (ii) we buy natural gas from and sell natural gas to Acadian Gas in connection with our normal business activities; and (iii) we are the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners in the near term and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

For additional information regarding Duncan Energy Partners, see *Recent Developments* under Item 1 of this annual report.

Omnibus Agreement. In connection with the initial public offering of common units by Duncan Energy Partners, our Operating Partnership also entered into an Omnibus Agreement with Duncan Energy Partners and certain of its subsidiaries that will govern our relationship with Duncan Energy Partners on the following matters:

§ indemnification for certain environmental liabilities, tax liabilities and right-of-way defects;

§ reimbursement of certain expenditures for South Texas NGL and Mont Belvieu Caverns;

§ a right of first refusal to the Operating Partnership on the equity interests in the current and future subsidiaries of Duncan Energy Partners and a right of first refusal on the material assets of these entities, other than sales of inventory and other assets in the ordinary course of business; and

§ a preemptive right with respect to equity securities issued by certain of Duncan Energy Partners subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

Indemnification for Environmental and Related Liabilities. Our Operating Partnership also agreed to indemnify Duncan Energy Partners after the closing of its initial public offering against certain environmental and related liabilities arising out of or associated with the operation of the assets before February 5, 2007. These liabilities include both known and unknown environmental and related liabilities. This indemnification obligation will terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage. In addition, Duncan Energy Partners is not entitled to indemnification until the aggregate amounts of its claims exceed $250 thousand. Liabilities resulting from a change of law after February 5, 2007 are excluded from the environmental indemnity provided by the Operating Partnership.

In addition, our Operating Partnership will indemnify Duncan Energy Partners for liabilities related to:

§ certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners on February 5, 2007 are located;

§ failure to obtain certain consents and permits necessary for Duncan Energy Partners to conduct its business that arise within three years after February 5, 2007; and

§ certain income tax liabilities related to the operation of the assets contributed to Duncan Energy Partner attributable to periods prior to February 5, 2007.

Reimbursement for Certain Expenditures. Our Operating Partnership has agreed to make additional contributions to Duncan Energy Partners as reimbursement for its 66% share of excess construction costs, if any, above (i) the $28.6 million of estimated capital expenditures to complete planned expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional planned brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. We estimate the costs to complete the planned expansion of the DEP South Texas NGL Pipeline after the closing of the Duncan Energy Partners initial public offering would be approximately $28.6 million, of which Duncan Energy Partners 66% share would be approximately $18.9 million. Duncan Energy Partners retained cash from the proceeds of its initial public offering in an amount equal to 66% of these estimated planned expansion costs. The Operating Partnership will make a capital contribution to South Texas NGL for its 34% share of such planned expansion costs.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 in connection with the acquisition of TEPPCO GP by a private company subsidiary of EPCO.

We received $42.9 million and a nominal amount from TEPPCO during the years ended December 31, 2006 and 2005, respectively, from the sale of hydrocarbon products. We paid TEPPCO $24.0 million and $17.2 million for NGL pipeline transportation and storage services during the years ended December 31, 2006 and 2005, respectively. We did not sell hydrocarbon products to TEPPCO or utilize its NGL pipeline transportation and storage services during the year ended December 31, 2004.

Purchase of Pioneer plant from TEPPCO. In March 2006, we paid TEPPCO $38.2 million for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to natural gas production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor. TEPPCO will have no continued involvement in the contracts or in the operations of the Pioneer facility.

Jonah Joint Venture with TEPPCO. In August 2006, we became a joint venture partner with TEPPCO in its Jonah Gas Gathering Company (Jonah), which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO plan to continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.3 Bcf/d and to significantly reduce system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to 2.0 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $302.0 million. The second portion of the expansion is expected to cost approximately $142.0 million and be completed by the end of 2007.

We manage the Phase V construction project. TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and TEPPCO will share distributions based on a formula that takes into account the respective capital contributions of the parties, including expenditures by TEPPCO prior to the expansion.

Since August 1, 2006, we and TEPPCO equally share in the construction costs of the Phase V expansion. During 2006, TEPPCO reimbursed us $109.4 million, which represents 50% of total Phase V costs incurred through December 31, 2006. We had a receivable of $8.7 million from TEPPCO at December 31, 2006 for Phase V expansion costs.

Upon completion of the expansion project and based on the formula in the joint venture partnership agreement, we expect to own an interest in Jonah of approximately 20%, with TEPPCO owning the remaining 80%. At December 31, 2006, we owned an approximate 14.4% interest in Jonah. We will operate the Jonah system.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. The ACG Committee of our general partner received a fairness opinion in connection with this transaction. In our Form 10-Q for the nine months ended September 30, 2006, we mistakenly reported that the Audit and Conflicts Committee of TEPPCO GP had also received a fairness opinion in connection with this transaction; however, they did not. The transaction was reviewed and recommended for approval by the Audit and Conflicts Committee of TEPPCO GP with assistance from an independent financial advisor.

We account for our investment in the Jonah joint venture using the equity method. As a result of entering into the Jonah joint venture, we reclassified $52.1 million expended on this project through July 31, 2006 (representing our 50% share at inception of the joint venture) from Other assets to Investments in and advances to unconsolidated affiliates on the Consolidated Balance Sheets. The remaining $52.1 million we spent through this date is included in the $109.4 million we billed TEPPCO (see above).

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. The acquired pipelines will be modified for natural gas service. The purchase of this asset was in accordance with the Board-approved management authorization policy.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million that is part of the DEP South Texas NGL Pipeline System. In addition, we entered into a lease with TEPPCO for a 11-mile interconnecting pipeline located in the Houston area. The primary term of this lease expires in September 2007, and will continue on a month-to-month basis subject to termination by either party upon 60 days notice. This pipeline is being leased by a subsidiary of Duncan Energy Partners in connection with operations on its DEP South Texas NGL Pipeline System until construction of a parallel pipeline is completed. These transactions were in accordance with the Board-approved management authorization policy.

Relationship with Employee Partnerships

EPE Unit I. In connection with the initial public offering of Enterprise GP Holdings, EPCO formed EPE Unit I to serve as an incentive arrangement for certain employees of EPCO through a profits interest in EPE Unit I. EPCO serves as the general partner of EPE Unit I. In connection with the closing of Enterprise GP Holdings initial public offering, EPCO Holdings, Inc., a wholly owned subsidiary of EPCO, borrowed $51.0 million under its credit facility and contributed the proceeds to its wholly-owned subsidiary, Duncan Family Interests, Inc. (Duncan Family Interests).

Subsequently, Duncan Family Interests contributed the $51.0 million to EPE Unit I as a capital contribution and was issued the Class A limited partner interest in EPE Unit I. EPE Unit I used the contributed funds to purchase 1,821,428 units directly from Enterprise GP Holdings at the initial public offering price of $28.00 per unit. Certain EPCO employees, including all of Enterprise Products GP s then current executive officers other than the Chairman, were issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of EPE Unit I.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of EPE Unit I, EPE Unit I will terminate at the earlier of five years following the closing of Enterprise GP Holdings initial public offering or a change in control of Enterprise GP Holdings or its general partner. EPE Unit I has the following material terms regarding its quarterly cash distribution to partners:

§ Distributions of Cashflow Each quarter, 100% of the cash distributions received by EPE Unit I from Enterprise GP Holdings will be distributed to the Class A limited partner until Duncan Family Interests has received an amount equal to the Class A preferred return (as defined below), and any remaining distributions received by EPE Unit I will be distributed to the Class B limited partners. The Class A preferred return equals 1.5625% per quarter, or 6.25% per annum, of the Class A limited partner s capital base. The Class A limited partner s capital base equals $51 million plus any unpaid Class A preferred return from prior periods, less any distributions made by EPE Unit I of proceeds from the sale of Enterprise GP Holdings units owned by EPE Unit I (as described below).

§ Liquidating Distributions Upon liquidation of EPE Unit I, units having a fair market value equal to the Class A limited partner 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 EPE Unit I sells any of the 1,821,428 Enterprise GP Holdings units that it owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in EPE Unit I 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 Enterprise GP Holdings 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 EPE Unit I will also lapse upon certain change of control events.

Since Enterprise GP Holdings has an indirect interest in us through its ownership of our general partner, EPE Unit I, including its Class B limited partners, may derive some benefit from our results of operations. Accordingly, a portion of the fair value of these equity awards is allocated to us under the EPCO administrative services agreement as a non-cash expense. We, Enterprise Products GP, Duncan Energy Partners, DEP Holdings and Enterprise GP Holdings will not reimburse EPCO, EPE Unit I or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to EPE Unit I, including the contribution of $51 million to EPE Unit I by Duncan Family Interests or the purchase of Enterprise GP Holdings units by EPE Unit I.

For the period that EPE Unit I was in existence during 2005, EPCO accounted for this equity-based award using the provisions of APB 25. Under APB 25, the intrinsic value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights (i.e. variable accounting). Upon our adoption of SFAS 123(R), we began recognizing compensation expense based upon the estimated grant date fair value of the Class B partnership equity awards. 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. For the years ended December 31, 2006 and 2005, we recorded $2.1 million and $2.0 million, respectively, of non-cash compensation expense for these awards associated with employees who work on our behalf.

EPE Unit II. In December 2006, EPE Unit II was formed to serve as an incentive arrangement for an executive officer of our general partner. The officer, who is not a participant in EPE Unit I, was granted a profits interest in EPE Unit II. EPCO serves as the general partner of EPE Unit II.

Duncan Family Interests contributed $1.5 million to EPE Unit II as a capital contribution and was issued the Class A limited partner interest in EPE Unit II. EPE Unit II used these funds to purchase on the open market 40,725 units of Enterprise GP Holdings on the open market at an average price of $36.91 per unit in December 2006. The officer was issued a Class B limited partner interest in EPE Unit II without any capital contribution. The significant terms of EPE Unit II (e.g. termination provisions, quarterly distributions of cashflow, liquidating distributions, forfeitures, and treatment of sale proceeds) are similar to those for EPE Unit I except that the Class A capital base for Duncan Family Interests is $1.5 million.

As with EPE Unit I, EPCO s non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of the officer s services. In accordance with SFAS 123(R), we recognize compensation expense associated with EPE Unit II based on the estimated grant date fair value of the Class B partnership equity award. Since EPE Unit II was formed in December 2006, we recorded a nominal amount of expense associated with this award during the year ended December 31, 2006.

See Note 5 of the Notes to Consolidated Financial Statements under Item 8 of this annual report for additional information regarding our accounting for equity awards.

EPCO 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 (the ASA). We and our general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner, and TEPPCO and its general partner, among other affiliates, are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services, and management 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 will allow us to participate as named insureds in its overall insurance program, with the associated premiums and other costs being allocated 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, with the offset to partners equity accounted for as a general contribution to our partnership. 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 2006, 2005 and 2004 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 2006, 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).

The ASA also addresses potential conflicts that may arise among us and our general partner, Duncan Energy Partners and its general partner, DEP Holdings, LLC (DEP Holdings) Enterprise GP Holdings and its general partner, and the EPCO Group, which includes EPCO and its affiliates (but does not include the aforementioned entities and their controlled affiliates). The administrative services agreement provides, among other things, that:

§ If a business opportunity to acquire *equity securities (as defined)* is presented to the EPCO Group, us and our general partner, Duncan Energy Partners, its general partner, and its operating partnership, or Enterprise GP Holdings and its general partner, then Enterprise GP Holdings will have the first right to pursue such opportunity. The term equity securities is 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.

Enterprise GP Holdings will be presumed to desire to acquire the equity securities until such time as its general partner advises the EPCO Group, Enterprise Products GP and DEP Holdings that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or 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 ACG 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 ACG Committee of EPE Holdings.

Partners and so notify the EPCO Group, EPE Holdings and DEP Holdings, Enterprise GP Holdings will have the second right to pursue such business opportunity, and will be presumed to desire to do so, until such time as EPE Holdings shall have determined to abandon the pursuit of such opportunity in accordance with the procedures described above, and shall have advised the EPCO Group that Enterprise GP Holdings has abandoned the pursuit of such acquisition.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, the EPCO Group may either pursue the business opportunity or offer the business opportunity to EPCO Holdings or TEPPCO, TEPPCO GP and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise GP Holdings, EPE Holdings, DEP Holdings, Duncan Energy Partners or its operating partnership, our general partner or us have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates. Likewise, TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise GP Holdings, EPE Holdings, DEP Holdings, Duncan Energy Partners or its operating partnership, our general partner or us.

On February 28, 2007, due to the substantial completion of inquires by the Federal Trade Commission (FTC) into EPCO s acquisition of TEPPCO GP, the parties to the ASA amended it to remove Exhibit B thereto, which had been adopted to address matters the parties anticipated the FTC may consider in its inquiry. Exhibit B had set forth certain separateness and screening policies and procedures among the parties that became unnecessary upon the issuance of the FTC s order in connection with the inquiry or were already otherwise reflected in applicable FTC, SEC, NYSE or other laws, standards or governmental regulations.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 16 of the Notes to Consolidated Financial Statements for a discussion of this alignment of commercial interests. Since we and our 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 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 $277.7 million, $318.8 million and $233.9 million for the years ended December 31, 2006, 2005 and 2004. In addition, we furnished $1.1 million in letters of credit on behalf of Evangeline at December 31, 2006.

§ 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 $34.9 million, $26.0 million and $23.2 million for the years ended December 31, 2006, 2005 and 2004. Additionally, revenues from Promix were $21.8 million, $25.8 million and $18.6 million for the years ended December 31, 2006, 2005 and 2004.

§ We perform management services for certain of our unconsolidated affiliates. These fees were $8.9 million, $8.3 million and $2.1 million for the years ended December 31, 2006, 2005 and 2004.

Relationship with Shell

Historically, Shell was considered a related party because it owned more than 10% of our limited partner interests 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 us to third parties, Shell owned less than 10% of our 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 us and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party in January 2005. At December 31, 2006, Shell owned 26,976,249, or 6.2%, of our common units, all of which have been registered for resale in the open market by us. At February 1, 2007, Shell owned 19,635,749, or 4.5%, of our common units.

For the year ended December 31, 2004, our revenues from Shell primarily reflected the sale of NGL and certain petrochemical products and the fees we charged for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflected the payment of energy-related expenses related to the Shell Processing Agreement and the purchase of NGL products. 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.

Review and Approval of Transactions with Related Parties

Our partnership agreement and ACG Committee charter set forth policies and procedures for the review and approval of certain transactions with persons affiliated with or related to us. As further described below, our partnership agreement and ACG Committee charter set forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the general partner or the ACG Committee. Under our partnership agreement, unless otherwise expressly provided therein or in the partnership agreements of the Operating Partnership, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by the general partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement, the partnership agreement of the Operating Partnership or any agreement contemplated by such agreements, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; *provided* that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our ACG Committee (Special Approval), as long as the material facts within the actual knowledge of the officers and directors of the General Partner and EPCO regarding the proposed transaction were disclosed to the committee at the time it gave its approval, or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its determination of what is fair and reasonable to the Partnership and in connection with its resolution of any conflict of interest to consider:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ any customary or accepted industry practices and any customary or historical dealings with a particular person;

§ any applicable generally accepted accounting practices or principles; and

§ such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

Our Board of Directors or our general partner may, in their discretion, request that our ACG Committee review and approve related party transactions. The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee s Special Approval is conclusively deemed fair and reasonable to us under the partnership agreement. The processes followed by our management in approving or obtaining approval of related party transactions are in accordance with our written management authorization policy, which has been approved by the Board.

Under our Board-approved management authorization policy, the officers of our general partner have authorization limits for purchases and sales of assets, capital expenditures, commercial and financial transactions and legal agreements that ultimately limit the ability of executives of our general partner to enter into transactions involving capital expenditures in excess of $100 million without Board approval. This policy covers all transactions, including transactions with related parties. For example, under this policy, the chairman of our general partner may approve capital expenditures or the sale or other disposition of our assets up to a $100 million limit. Furthermore, any two of the chief executive officer and senior executives who are directors of our general partner may approve capital expenditures or the sale or other disposition of our assets up to a $100 million limit and individually may approve capital expenditures or the sale or other disposition of our assets up to $50 million. These senior executives have also been granted full approval authority for commercial, financial and service contracts.

In submitting a matter to the ACG Committee, the Board or the general partner may charge the committee with reviewing the transaction and providing the Board a recommendation, or it may delegate to the committee the power to approve the matter. When so engaged, the ACG Committee Charter currently provides that, unless the ACG Committee otherwise determines, the ACG Committee shall perform the following functions:

§ Review a summary of the proposed transaction(s) that outlines (i) its terms and conditions (explicit and implicit), (ii) a brief history of the transaction, and (iii) the impact that the transaction will have on our unitholders and personnel, including earnings per unit and distributable cash flow.

§ Review due diligence findings by management and make additional due diligence requests, if necessary.

§ Engage third-party independent advisors, where necessary, to provide committee members with comparable market values, legal advice and similar services directly related to the proposed transaction.

§ Conduct interviews regarding the proposed transaction with the most knowledgeable company officials to ensure that the committee members have all relevant facts before rendering their judgment.

In the normal course of business, our management routinely reviews all other related party transactions, including proposed asset purchases and business combinations and purchases and sales of product. As a matter of course, management reviews the terms and conditions of the proposed transactions, performs appropriate levels of due diligence and assesses the impact of the transaction on our partnership.

The ACG Committee does not separately review transactions covered by our administrative services agreement with EPCO, which agreement has previously been approved by the ACG Committee and/or the Board. The administrative services agreement governs numerous day-to-day transactions between us and our subsidiaries and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs for those services. For a description of the administrative services agreement, please read *Relationship with EPCO and affiliates* *Administrative Services Agreement* within this Item 13.

Since the beginning of the last fiscal year of our partnership, the ACG Committee reviewed and approved the purchase of the Pioneer plant from TEPPCO and Jonah Joint Venture with TEPPCO referenced under this Item 13. All other transactions with related parties referenced under this Item 13 were either governed by the administrative services agreement or effected under our written management authorization policy.

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Statement of Transactions with EPCO and Affiliates during 2006

The following table presents a detailed statement of amounts we paid to EPCO and affiliates during 2006 by transaction category (dollars in thousands). All of these transactions were covered under the review and approval processes of either the ACG Committee or management.

Revenues:	
Sales of NGL products	$ 98,645
Other	26
Total revenues related to EPCO and affiliates	$ 98,671
Operating costs and expenses:	
Purchase of NGL products, including freight and storage	$ 86,383
Reimbursement of operating employee costs	200,324
Recognition of non-cash retained lease expense	2,109
Office space lease expense	2,168
Other	20,553
Total operating costs and expenses related to EPCO and affiliates	311,537
General and administrative costs:	
Reimbursement of overhead employee costs	15,989
Office space lease expense	1,781
Other	23,495
Total general and administrative costs related to EPCO and affiliates	41,265
Total costs and expenses related to EPCO and affiliates	$ 352,802
Cash distributions paid to Enterprise Products GP by us	$ 101,805
Cash distributions paid by us to our common units beneficially owned by EPCO (see Item 12)	$ 237,006
Non-cash expense amount recognized in connection with Employee Partnership equity awards	$ 2,146

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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,	
	2006	**2005**
Audit Fees (1)	$ 5,563	$ 4,892
Audit-Related Fees (2)	13	14
Tax Fees (3)	319	407
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.

(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 ACG Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the ACG 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 ACG 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 ACG 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 ACG 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 rules of the American Institute of Certified Public Accountants. 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 ACG Committee to increase the approved amount and the reasons for the 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 ACG 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 ACG Committee s pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG 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, see *Index to Financial Statements* under Item 8 of this annual report.

(a)(2) Financial Statement Schedules

Schedule II Valuation and Qualifying Accounts is included under Item 8 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 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 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 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 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 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 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 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 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 the Form 8-K filed April 21, 2004).

Exhibit Number	Exhibit*
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 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 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 Form 8-K filed December 15, 2003).
3.1	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 Form 8-K filed August 10, 2005).
3.2	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 Form 8-K filed September 1, 2005).
3.3	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 Form 8-K filed July 1, 2005).
3.4	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.5	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.6	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P. Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
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 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 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 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 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 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 Form 8-K filed January 25, 2001).
4.7	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
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).

Exhibit Number	Exhibit*
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 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 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 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 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 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 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 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 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 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 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 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 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 Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

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Exhibit Number	Exhibit*
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 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 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 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 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 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 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 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 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 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 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).

Exhibit Number	Exhibit*
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 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 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 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 Form 8-K filed December 21, 2005.)
4.46	Second Amendment dated June 22,2006, 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 4.6 to Form 10-Q filed August 8, 2006).
4.47#	Third Amendment dated January 5, 2007, 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.
4.48	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.2 to Form 8-K filed July 19, 2006).
4.49	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K file July 19, 2006).

4.50	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.51	Purchase Agreement dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P., as Guarantor, and Enterprise Products Partners L.P., as Buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).

Exhibit Number	Exhibit*
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 Registration Statement 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 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).
10.4***	Form of Option Grant Award under 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to 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 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	Fourth 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, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership L.P., 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 January 30, 2007, but effective as of February 5, 2007 (incorporated by reference to Exhibit 10 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).
10.8#	Amendment No. 1 to the Fourth Amended and Restated Administrative Services Agreement dated February 28, 2007.
10.9***	EPE Unit L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P., Commission file no. 1-32610, on September 1, 2005).
10.10***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on May 8, 2006).
10.11***	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 Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. 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 Form S-1 Registration

	Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.13#***	EPE Unit II, L.P. Agreement of Limited Partnership.
10.14	Omnibus Agreement, dated as of February 5, 2007 by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC (incorporated by reference to Exhibit 10.19 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).

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Exhibit Number	Exhibit*
10.15	Contribution, Conveyance And Assumption Agreement dated as of February 5, 2007, by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC and DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 1.1 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).
10.16***	Form of Unit Appreciation Right Grant (Enterprise Products GP, LLC Directors) based upon the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings on May 8, 2006).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2006, 2005, 2004, 2003 and 2002.
18.1	Letter regarding Change in Accounting Principles dated May 4, 2004 (incorporated by reference to Exhibit 18.1 to Form 10-Q filed May 10, 2004).
21.1#	List of subsidiaries as of February 28, 2007.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Robert G. Phillips for Enterprise Products Partners L.P. for the December 31, 2006 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2006 annual report on Form 10-K.
32.1#	Section 1350 certification of Robert G. Phillips for the December 31, 2006 annual report on Form 10-K.
32.2#	Section 1350 certification of Michael A. Creel for the December 31, 2006 annual report on Form 10-K.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

*** Identifies management contract and compensatory plan arrangements.

Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on February 28, 2007.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)
By: Enterprise Products GP, LLC, as general partner
By: */s/ Michael J. Knesek* Senior Vice President, Controller and Principal Accounting Officer of the general partner

Michael J. Knesek

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 28, 2007.

Signature	Title (Position with Enterprise Products GP, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Robert G. Phillips Robert G. Phillips	Director, President and Chief Executive Officer
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director, Group Executive Vice President and Chief Operating Officer
/s/ Michael A. Creel Michael A. Creel	Director, Executive Vice President and Chief Financial 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 Treasurer
/s/ E. William Barnett E. William Barnett	Director
/s/ Charles M. Rampacek Charles M. Rampacek	Director
/s/ Rex C. Ross Rex C. Ross	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Accounting Firm

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related statements of consolidated operations, consolidated comprehensive income, consolidated cash flows and consolidated partners equity for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule in Item 15. These financial statements and financial statement schedule are the responsibility of the Company s 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP
Houston, Texas
February 28, 2007

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ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22,619	$ 42,098
Restricted cash	23,667	14,952
Accounts and notes receivable trade, net of allowance for doubtful accounts of $23,406 at December 31, 2006 and $37,329 at December 31, 2005	1,306,290	1,448,026
Accounts receivable related parties	16,738	6,557
Inventories	423,844	339,606
Prepaid and other current assets	129,000	120,208
Total current assets	1,922,158	1,971,447
Property, plant and equipment, net	9,832,547	8,689,024
Investments in and advances to unconsolidated affiliates	564,559	471,921
Intangible assets, net of accumulated amortization of $251,876 at December 31, 2006 and $163,121 at December 31, 2005	1,003,955	913,626
Goodwill	590,541	494,033
Deferred tax asset	1,855	3,606
Other assets	74,103	47,359
Total assets	$ 13,989,718	$ 12,591,016
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 277,070	$ 265,699
Accounts payable related parties	6,785	23,367
Accrued gas payables	1,364,493	1,372,837
Accrued expenses	35,763	30,294
Accrued interest	90,865	71,193
Other current liabilities	209,945	126,881
Total current liabilities	1,984,921	1,890,271
Long-term debt: (see Note 14)		
Senior debt obligations principal	4,779,068	4,866,068
Junior Subordinated Notes A principal	550,000	
Other	(33,478)	(32,287)
Total long-term debt	5,295,590	4,833,781
Deferred tax liabilities	13,723	
Other long-term liabilities	86,121	84,486

Minority interest	129,130	103,169
Commitments and contingencies		
Partners equity:		
Limited Partners		
Common units (431,303,193 units outstanding at December 31, 2006 and 389,109,564 units outstanding at December 31, 2005)	6,320,577	5,542,700
Restricted common units (1,105,237 units outstanding at December 31, 2006 and 751,604 units outstanding at December 31, 2005)	9,340	18,638
General partner	129,175	113,496
Accumulated other comprehensive income	21,141	19,072
Deferred compensation		(14,597)
Total partners equity	6,480,233	5,679,309
Total liabilities and partners equity	$ 13,989,718	$ 12,591,016

See Notes to Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31, 2006	2005	2004
Revenues:			
Third parties	$ 13,587,739	$ 11,902,187	$ 7,517,052
Related parties	403,230	354,772	804,150
Total (see Note 16)	13,990,969	12,256,959	8,321,202
Costs and expenses:			
Operating costs and expenses			
Third parties	12,745,948	11,229,528	6,938,229
Related parties	343,143	316,697	966,107
Total operating costs and expenses	13,089,091	11,546,225	7,904,336
General and administrative costs			
Third parties	22,126	21,312	17,352
Related parties	41,265	40,954	29,307
Total general and administrative costs	63,391	62,266	46,659
Total costs and expenses	13,152,482	11,608,491	7,950,995
Equity in income of unconsolidated affiliates	21,565	14,548	52,787
Operating income	860,052	663,016	422,994
Other income (expense):			
Interest expense	(238,023)	(230,549)	(155,740)
Interest income	7,589	5,237	2,083
Other, net	467	134	32
Other expense	(229,967)	(225,178)	(153,625)
Income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles	630,085	437,838	269,369
Provision for income taxes	(21,323)	(8,362)	(3,761)
Income before minority interest and the cumulative effect of changes in accounting principles	608,762	429,476	265,608
Minority interest	(9,079)	(5,760)	(8,128)
	599,683	423,716	257,480

Income before the cumulative effect of changes in accounting principles						
Cumulative effect of changes in accounting principles (see Note 8)		1,472		(4,208)		10,781
Net income	$	601,155	$	419,508	$	268,261
Net income allocation: (see Note 15)						
Limited partners interest in net income	$	504,156	$	348,512	$	231,153
General partner interest in net income	$	96,999	$	70,996	$	37,108
Earnings per unit: (see Note 19)						
Basic and diluted income per unit before changes in accounting principles	$	1.22	$	0.92	$	0.83
Basic and diluted income per unit	$	1.22	$	0.91	$	0.87

See Notes to Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2006	**2005**	**2004**
Net income	$ 601,155	$ 419,508	$ 268,261
Other comprehensive income:			
Cash flow hedges:			
Net commodity financial instrument gains during period	7,574		1,434
Less: Reclassification adjustment for gain included in net income related to commodity financial instruments		(1,434)	
Net interest rate financial instrument gains during period			19,405
Less: Amortization of cash flow financing hedges	(4,234)	(4,048)	(1,275)
Total cash flow hedges	3,340	(5,482)	19,564
Foreign currency translation adjustment	(807)		
Total other comprehensive income	2,533	(5,482)	19,564
Comprehensive income	$ 603,688	$ 414,026	$ 287,825

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31, 2006	2005	2004
Operating activities:			
Net income	$ 601,155	$ 419,508	$ 268,261
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion in operating costs and expenses	440,256	413,441	193,734
Depreciation and amortization in general and administrative costs	7,186	7,184	1,650
Amortization in interest expense	766	152	3,503
Equity in income of unconsolidated affiliates	(21,565)	(14,548)	(52,787)
Distributions received from unconsolidated affiliates	43,032	56,058	68,027
Provision for impairment of long-lived asset	88		4,114
Cumulative effect of changes in accounting principles	(1,472)	4,208	(10,781)
Operating lease expense paid by EPCO, Inc.	2,109	2,112	7,705
Minority interest	9,079	5,760	8,128
Gain on sale of assets	(3,359)	(4,488)	(15,901)
Deferred income tax expense	14,427	8,594	9,608
Changes in fair market value of financial instruments	(51)	122	5
Net effect of changes in operating accounts (see Note 22)	83,418	(266,395)	(93,725)
Net cash flows provided by operating activities	1,175,069	631,708	391,541
Investing activities:			
Capital expenditures	(1,341,070)	(864,453)	(182,057)
Contributions in aid of construction costs	60,492	47,004	8,865
Proceeds from sale of assets	3,927	44,746	6,882
Decrease (increase) in restricted cash	(8,715)	11,204	(12,305)
Cash used for business combinations (see Note 12)	(276,500)	(326,602)	(696,745)
Acquisition of intangible assets		(1,750)	(1,652)
Investments in unconsolidated affiliates	(138,266)	(87,342)	(57,948)
Advances from (to) unconsolidated affiliates	10,844	(702)	(6,464)
Return of investment from unconsolidated affiliate		47,500	
Cash used in investing activities	(1,689,288)	(1,130,395)	(941,424)
Financing activities:			
Borrowings under debt agreements	3,378,285	4,192,345	5,934,505
Repayments of debt	(2,907,000)	(3,630,611)	(5,808,877)
Debt issuance costs	(8,955)	(9,297)	(19,911)
Distributions paid to partners	(843,292)	(716,699)	(438,765)
Distributions paid to minority interests	(8,831)	(5,724)	(6,440)
Contributions from minority interests	27,578	39,110	9,585

Contributions from general partner related to issuance of restricted units			
Net proceeds from issuance of common units	857,187	646,928	846,077
Treasury units reissued			8,394
Settlement of cash flow financing hedges			19,405
Cash provided by financing activities	494,972	516,229	543,973
Effect of exchange rate changes on cash	(232)		
Net change in cash and cash equivalents	(19,247)	17,542	(5,910)
Cash and cash equivalents, January 1	42,098	24,556	30,466
Cash and cash equivalents, December 31	$ 22,619	$ 42,098	$ 24,556

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS 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	Treasury units	Deferred Comp.	AOCI	Total
Balance, December 31, 2003	$ 1,683,133	$ 34,349	$ (16,519)	$	$ 4,990	$ 1,705,953
Net income	231,153	37,108				268,261
Operating leases paid by EPCO, Inc.	7,551	154				7,705
Cash distributions to partners	(394,434)	(40,440)				(434,874)
Unit option reimbursements to EPCO, Inc.	(3,813)	(78)				(3,891)
Net proceeds from sales of common units	789,758	16,117				805,875
Proceeds from conversion of Series F2 convertible units to common units	38,800	792				39,592
Proceeds from exercise of unit options	398	8				406
Value of equity interests granted to complete GulfTerra Merger	2,854,275	58,252		(1,755)		2,910,772
Other issuance of restricted units	9,922	202		(9,922)		202
Amortization of deferred compensation				826		826
Treasury units issued to satisfy unit options	524	11	7,859			8,394
Cash flow hedges					19,564	19,564
Balance, December 31, 2004	5,217,267	106,475	(8,660)	(10,851)	24,554	5,328,785
Net income	348,512	70,996				419,508
Operating leases paid by EPCO, Inc.	2,070	42				2,112
Cash distributions to partners	(630,560)	(76,752)				(707,312)
Unit option reimbursements to EPCO, Inc.	(9,199)	(188)				(9,387)
Net proceeds from sales of common units	612,616	12,502				625,118
	21,374	436				21,810

Proceeds from exercise of unit options						
Issuance of restricted units	9,478	177		(9,480)		175
Forfeiture of restricted units	(2,663)	(38)		2,361		(340)
Amortization of Employee Partnership awards	1,358	28				1,386
Amortization of deferred compensation				3,373		3,373
Cancellation of treasury units	(8,915)	(182)	8,660			(437)
Cash flow hedges					(5,482)	(5,482)
Balance, December 31, 2005	5,561,338	113,496		(14,597)	19,072	5,679,309
Net income	504,156	96,999				601,155
Operating leases paid by EPCO, Inc.	2,067	42				2,109
Cash distributions to partners	(739,632)	(101,805)				(841,437)
Unit option reimbursements to EPCO, Inc.	(1,818)	(41)				(1,859)
Net proceeds from sales of common units	830,825	16,943				847,768
Common units issued to Lewis in connection with Encinal acquisition	181,112	3,705				184,817
Proceeds from exercise of unit options	5,601	114				5,715
Change in accounting method for equity awards (see Note 5)	(15,815)	(307)		14,597		(1,525)
Change in funded status of pension and postretirement plans, net of tax					(464)	(464)
Amortization of equity awards	8,282	155				8,437
Foreign currency translation adjustment					(807)	(807)
Acquisition-related disbursement of cash (see Note 17)	(6,199)	(126)				(6,325)
Cash flow hedges					3,340	3,340
Balance, December 31, 2006	$ 6,329,917	$ 129,175	$	$	$ 21,141	$ 6,480,233

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol EPD. Unless the context requires otherwise, references to we, us, our, or Enterprise Products Partners are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids (NGLs) related businesses of EPCO, Inc. (EPCO). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our Operating Partnership). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. (Enterprise GP Holdings), a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol EPE. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (EPE Holdings), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

In September 2004, we completed the GulfTerra Merger transactions, whereby 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 expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. In connection with the GulfTerra Merger, we purchased various midstream energy assets from El Paso Corporation (El Paso) that are located in South Texas (referred to as the STMA acquisition).

References to TEPPCO mean TEPPCO Partners, L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol TPP. References to TEPPCO GP refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by a private company subsidiary of EPCO.

References to *Employee Partnerships* mean EPE Unit L.P. and EPE Unit II, L.P., collectively, which are private company affiliates of EPCO. References to EPE Unit I and EPE Unit II refer to EPE Unit L.P. and EPE Unit II, L.P., respectively.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. (Duncan Energy Partners), completed an initial public offering of its common units (see Note 25). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses (see Note 17). The formation of Duncan Energy Partners had no effect on our financial statements at December 31, 2006. For financial reporting purposes, we will continue to consolidate the financial statements of Duncan Energy Partners with those of our own (using our historical carrying basis in such entities) and reflect its operations in our business segments. The public owners of Duncan Energy Partners common units will be presented as a noncontrolling interest in our consolidated financial statements beginning in February 2007. The public owners of Duncan Energy Partners have no direct equity interests in us as a result of this transaction. The borrowings of Duncan Energy Partners will be presented as part of our consolidated debt.

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research, and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts. Our allowance for doubtful accounts was $23.4 million and $37.3 million at December 31, 2006 and 2005, 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. 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 similar transactions, (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, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

Consolidation Policy

We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. 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 also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership.

If the investee is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the investee s operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee s operating and financial policies. 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 balance sheet (or those of our equity method investees) 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 us 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 management and legal counsel evaluate 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 (see Note 4). Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue.

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 19.

Employee Benefit Plans

In 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.

Statement of Financial Accounting Standards (SFAS) 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R*), requires businesses to record the over-funded or under-funded status of defined benefit pension and other postretirement plans as an asset or liability at a measurement date and to recognize annual changes in the funded status of each plan through comprehensive income. At December 31, 2006, Dixie adopted the provisions of SFAS 158. See Note 6.

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 a 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 for remediation costs associated with mercury gas meters. The balance of this environmental liability was $20.3 million and $21.0 million at December 31, 2006 and 2005, respectively. At December 31, 2006 and 2005, total reserves for environmental liabilities, including those related to the mercury gas meters, were $24.2 million and $22.1 million. At December 31, 2006, $7.1 million of this liability is classified as current.

Costs of environmental compliance and monitoring aggregated $3.6 million, $3.3 million and $1.9 million during 2006, 2005 and 2004, respectively.

Equity Awards

In connection with the incentive plans of EPCO and its affiliates, we record amounts related to unit option and restricted unit awards and profits interests. See Note 5.

We currently account for our equity awards using the provisions of SFAS 123(R), *Share-Based Payment.* Prior to January 1, 2006, our 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 equity awards based on the fair value of the award at grant date. The fair value of an equity award is estimated using option pricing models (Black-Scholes or binomial models). Under SFAS 123(R), the fair value of an award is amortized to earnings on a straight-line basis over the requisite service or vesting period. On January 1, 2006, we reclassified previously recognized deferred compensation related to nonvested awards due to the adoption of SFAS 123(R).

The following table discloses the pro forma effect of equity-based compensation amounts on our net income and earnings per unit for the years ended December 31, 2005 and 2004 as if we had applied the provisions of SFAS 123(R) instead of APB 25. The effects of applying SFAS 123(R) in the following pro forma disclosures may not be indicative of future amounts as additional awards in future years are anticipated. No pro forma adjustment to earnings is required for our restricted units in 2005 and 2004 since compensation expense related to these awards was based on their estimated fair values.

	For the Year Ended December 31,	
	2005	**2004**
Reported net income	$419,508	$268,261
Additional compensation expense that would have been recorded for unit options	(708)	(932)
Reduction in compensation expense related to awards of profits interests in EPE Unit L.P.	1,271	
Pro forma net income	$420,071	$267,329
Basic and Diluted earnings per unit:		
As reported	$ 0.91	$ 0.87
Pro forma	$ 0.91	$ 0.87

Estimates

Preparing our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (or 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. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Exchange Contracts

Exchanges are contractual agreements for the movements of NGLs and certain 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 settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs, such items are recognized in our consolidated financial statements 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, foreign currency and certain anticipated transactions. We recognize these transactions on our 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 incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on 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 risk and the related 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 its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings. See Note 7.

Foreign Currency Translation

In October 2006, we acquired all of the outstanding stock of an affiliated NGL marketing company located in Canada (see Note 15). Financial statements of this foreign operation are translated into U.S. dollars from the Canadian dollar, its functional currency, using the current rate method. Assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, while revenue and expense items are translated at average rates of exchange during the reporting period. Exchange gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive income in the accompanying Consolidated Balance Sheets.

Our net cash flows from this Canadian subsidiary may be adversely affected by changes in foreign currency exchange rates. We attempt to hedge this currency risk (see Note 7).

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Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis during the second quarter of each year or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 13.

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 when 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 asset carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset s carrying value over its estimated fair value is recorded. 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 price indicators or, in the absence of such data, appropriate valuation techniques.

We recorded non-cash asset impairment charges of $0.1 million in 2006 and $4.1 million in 2004, 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 our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to 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 we determine that the loss in value of an investment is other than a temporary decline, we record a charge to earnings to adjust the carrying value of the investment to its estimated fair value.

During 2006, we evaluated our investment in Neptune Pipeline Company, LLC (Neptune) for impairment. As a result of this evaluation, we recorded a $7.4 million non-cash impairment charge that is a component of equity income from unconsolidated affiliates for the year ended December 31, 2006. We had no such impairment charges during the years ended December 31, 2005 or 2004. See Note 11.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Texas State Margin Tax and certain federal and state tax obligations of Seminole Pipeline Company (Seminole) and Dixie, both of which are consolidated subsidiaries of ours. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

In May 2006, the State of Texas enacted a new business tax (the Texas Margin Tax) that replaced its franchise tax. In general, legal entities that conduct business in Texas are subject to the Texas Margin Tax. Limited partnerships, limited liability companies, corporations and limited liability partnerships are examples of the types of entities that are subject to the Texas Margin Tax. As a result of the change in tax law, our tax status in the State of Texas will change from non-taxable to taxable. See Note 18.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Since we do not have access to information regarding each partner s tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

Inventories

Inventories primarily consist of NGLs, certain petrochemical products and natural gas volumes that 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 purchase from third parties or 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 (including freight-in charges that 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.

Minority Interest

As presented in our Consolidated Balance Sheets, minority interest represents third-party ownership interests in the net assets of our consolidated 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 ownership interest in such amounts presented as minority interest. As presented in our Statements of Consolidated Operations, minority interest expense reflects the allocation of earnings to third party investors. As presented in our Statements of Consolidated Cash Flows, distributions to and contributions from minority interests represent cash payments and cash contributions, respectively, from such third-party investors.

At December 31, 2005 and 2006, our consolidated subsidiaries with third party minority interest owners were Seminole, Dixie, Tri-States Pipeline LLC (Tri-States), Independence Hub, LLC (Independence Hub), Wilprise Pipeline Company LLC and Belle Rose NGL Pipeline LLC (Belle Rose). We will consolidate the financial statements of Duncan Energy Partners with those of our own, with minority interest treatment for the units of Duncan Energy Partners owned by unitholders other than us.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled (i) on a monthly basis, (ii) at the end of the agreement or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2006 and 2005, our natural gas imbalance receivables, net of allowance for doubtful accounts, were $97.8 million and $89.4 million, respectively, and are reflected as a component of Accounts and notes receivable trade on our Consolidated Balance Sheets. At December 31, 2006 and 2005, our imbalance payables were $51.2 million and $80.5 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 additions, improvements and other enhancements to property, plant and equipment are capitalized and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. For financial statement purposes, depreciation is recorded based on the estimated useful lives of the related assets primarily using the straight-line method. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes. See Note 10.

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 their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. To the extent we do not settle an ARO liability at our recorded amounts, we will incur a gain or loss.

Reclassifications

A reclassification was made to the Statement of Consolidated Cash Flows for the year ended December 31, 2004 in the investing activities section to conform to current presentations of similar items. With respect to our December 2004 acquisition of certain assets, we reclassified our $27.9 million purchase price from Cash used for business combinations, net of cash received to Capital Expenditures ($26.2 million) and Acquisition of intangible assets ($1.7 million).

Restricted Cash

Restricted cash represents amounts held by (i) a brokerage firm in connection with our commodity financial instruments portfolio and physical natural gas purchases made on the NYMEX exchange and (ii) us for the future settlement of current liabilities we assumed in connection with our acquisition of a Canadian affiliate in October 2006.

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 considered start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

Note 3. Recent Accounting Developments

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

Emerging Issues Task Force Issue (EITF) No. 06-3

EITF 06-3, *How Taxes Collected From Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)* requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. This guidance specifically applies to taxes imposed by governmental authorities on revenue-producing transactions between sellers and customers (gross receipts taxes are excluded). We adopted EITF 06-3 on January 1, 2007. As a matter of policy, we have consistently reported such taxes on a net basis.

SFAS 155

SFAS 155, *Accounting for Certain Hybrid Financial Instruments*, amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, and resolves issues addressed in Statement 133 Implementation Issue D1, *Application of Statement 133 to Beneficial Interests to Securitized Financial Assets*. A hybrid financial instrument is one that embodies both an embedded derivative and a host contract. For certain hybrid financial instruments, SFAS 133 requires an embedded derivative instrument be separated from the host contract and accounted for as a separate derivative instrument. SFAS 155 amends SFAS 133 to provide a fair value measurement alternative for certain hybrid financial instruments that contain an embedded derivative that would otherwise be recognized as a derivative separately from the host contract. For hybrid financial instruments within its scope, SFAS 155 allows the holder of the instrument to make a one-time, irrevocable election to initially and subsequently measure the instrument in its entirety at fair value instead of separately accounting for the embedded derivative and host contract. This guidance was effective January 1, 2007, and our adoption of this guidance had no impact on our financial position, results of operations or cash flows.

SFAS 157

SFAS 157, *Fair Value Measurements*, defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. The statement emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period. SFAS 157 is effective for fiscal years beginning after December 15, 2007 and we will be required to adopt SFAS 157 on January 1, 2008. We do not believe that SFAS 157 will have a material impact on our financial position, results of operations, and cash flows since we already apply its basic concepts in measuring fair values used to record various transactions such as business combinations and asset acquisitions.

SFAS 159

SFAS 159, *Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115,* permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact that the adoption of SFAS 159 will have on our financial statements.

Financial Accounting Standards Board Interpretation (FIN) No. 48

In accordance with FIN 48, *Accounting for Uncertainty in Income Taxes*, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with a more than a 50% chance of being realized upon settlement. We did not recognize any such amounts at December 31, 2006. This guidance is effective January 1, 2007, and our adoption of this guidance is not anticipated to have a material impact on our financial position, results of operations or cash flows.

See Note 8 for new accounting principles adopted.

Note 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 contracts, fee-based contracts, hybrid contracts (these agreements include both percent-of-liquids and fee-based components) 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 stream. The producer retains title to the remaining percentage of mixed NGLs we extract under percent-of-liquids contract. 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 (i.e. fee-based arrangement), 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 various processing activities and purchased 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 Federal Energy Regulatory Commission (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. With respect to capacity reservation agreements, we collect a fee for reserving space (typically in millions of barrels) for a customer s product in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. We also collect excess storage fees when customers exceed their reservation amounts. Such excess storage fees are recognized in the period of occurrence.

Revenues from product terminalling agreements (applicable to our import and export operations) are recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. In our export operations, we may also record revenues related to demand payments we charge customers who reserve the use of 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 as 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. Revenues associated with these fee-based contracts are recognized when volumes have been physically delivered for the 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 customers. 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) a monthly demand payment, which is associated with storage capacity reservations and paid regardless of the customer s actual usage of the storage facilities, and (ii) a storage fee per unit of volume stored at the facilities. Revenues from demand payments are recognized during 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 payments and commodity charges. Demand payments represent fixed-fees charged to customers who use our offshore platforms regardless of the volume the customer delivers to the platform. Such demand payments generally expire after a contractual period of time subject to certain cancellation conditions. 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. Revenues for both platform services are recognized in the period the services are provided.

Petrochemical Services

We enter into isomerization and propylene fractionation fee-based processing arrangements and certain 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 our 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.

Note 5. Accounting for Equity Awards

Effective January 1, 2006, we adopted SFAS 123(R) to account for equity awards (see Note 8). Prior to our adoption of SFAS 123(R), we accounted for equity awards using the intrinsic value method described in APB 25. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of an equity award is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an award is amortized to earnings on a straight-line basis over the requisite service or vesting period.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to our restricted common units was reversed on January 1, 2006.

Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit L.P. (EPE Unit I) and the issuance of restricted units. The effects of applying SFAS 123(R) during the year ended December 31, 2006 did not have a material effect on our net income or basic and diluted earnings per unit.

Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard.

Unit Options

Under EPCO s 1998 Long-Term Incentive Plan (the 1998 Plan), non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO s key employees who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

In order to fund its obligations under the 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. 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.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on our common units, and expected unit price volatility of our common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

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The information in the following table presents unit option activity under the 1998 Plan for the periods indicated:

	Number of Units	Weighted-average strike price (dollars/unit)	Weighted-average remaining contractual term (in years)	Aggregate Intrinsic Value [1]
Outstanding at December 31, 2003	1,938,000	$ 16.07		
Granted [2]	910,000	22.17		
Exercised	(385,000)	12.79		
Outstanding at December 31, 2004	2,463,000	18.84		
Granted [3]	530,000	26.49		
Exercised	(826,000)	14.77		
Forfeited	(85,000)	24.73		
Outstanding at December 31, 2005	2,082,000	22.16		
Granted [4]	590,000	24.85		
Exercised	(211,000)	15.95		
Forfeited	(45,000)	24.28		
Outstanding at December 31, 2006	2,416,000	23.32	7.61	$ 4,808
Options exercisable at:				
December 31, 2004	1,154,000	$ 14.65	6.18	$13,768
December 31, 2005	727,000	$ 19.19	5.54	$ 3,503
December 31, 2006	591,000	$ 20.85	5.11	$ 4,808

(1) Aggregate intrinsic value reflects fully vested unit options at December 31, 2006.

(2) The total grant date fair value of these awards was $2.1 million based on the following assumptions: (i) expected life

of options of seven years; (ii) risk-free interest rate of 4.0%; (iii) expected distribution yield on our units of 8.8%; and (iv) expected unit price volatility of 28.6%.

(3) The total grant date fair value of these awards was $0.7 million based on the following assumptions: (i) expected life of options of seven years; (ii) risk-free interest rate of 4.2%; (iii) expected distribution yield on our units of 9.2%; and (iv) expected unit price volatility of 20.0%.

(4) The total grant date fair value of these awards was $1.2 million based on the following assumptions: (i) expected life of options of seven years; (ii) risk-free interest rate of 5.0%;

(iii) expected distribution yield on our units of 8.9%; and

(iv) expected unit price volatility of 23.5%.

The total intrinsic value of unit options exercised during the year ended December 31, 2006 was $2.2 million. We recognized $0.7 million of compensation expense associated with unit options during the year ended December 31, 2006.

As of December 31, 2006, there was an estimated $2.3 million of total unrecognized compensation cost related to nonvested unit options granted under the 1998 Plan. That cost is expected to be recognized over a weighted-average period of 2.2 years in accordance with the EPCO administrative services agreement (see Note 17).

During the year ended December 31, 2006, we received cash of $5.6 million from the exercise of unit options, and our option-related reimbursements to EPCO were $1.8 million.

Restricted Units

Under the 1998 Plan, we may issue restricted common units to key employees of EPCO and directors of our general partner. The 1998 Plan provides for the issuance of 3,000,000 restricted common units, of which 1,900,443 remain authorized for issuance at December 31, 2006.

In general, our restricted unit awards allow recipients to acquire the underlying common units at no cost to the recipient once a defined vesting period expires, subject to certain forfeiture provisions. The restrictions on such units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. The fair value of such restricted units is based

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on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures.

The following table summarizes information regarding our restricted units for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at January 1, 2004		
Granted (2)	488,525	$ 22.89
Restricted units at December 31, 2004	488,525	
Granted (3)	362,011	$ 26.43
Vested	(6,484)	$ 22.00
Forfeited	(92,448)	$ 24.03
Restricted units at December 31, 2005	751,604	
Granted (4)	466,400	$ 25.21
Vested	(42,136)	$ 24.02
Forfeited	(70,631)	$ 22.86
Restricted units at December 31, 2006	1,105,237	

(1) Determined by dividing the aggregate grant date fair value of awards (before allowance for forfeitures) by the number of awards issued

(2) Aggregate grant date fair value of restricted unit awards issued during 2004 was $10.3 million based on grant date market prices of our common units ranging from $20.95 to

$23.31 per unit and an estimated forfeiture rate of 8.2%.

(3) Aggregate grant date fair value of restricted unit awards issued during 2005 was $8.8 million based on grant date market prices of our common units ranging from $25.83 to $26.95 per unit and an estimated forfeiture rate of 8.2%.

(4) Aggregate grant date fair value of restricted unit awards issued during 2006 was $10.8 million based on grant date market prices of our common units ranging from $24.85 to $27.45 per unit and estimated forfeiture rates ranging from 7.8% to 9.8%.

The total fair value of restricted units that vested during the year ended December 31, 2006 was $1.1 million.

During the year ended December 31, 2006, we recognized $4.1 million of compensation expense in connection with restricted units.

As of December 31, 2006, there was $17.5 million of total unrecognized compensation cost related to restricted units. We will recognize our share of such costs in accordance with the EPCO administrative services agreement. At December 31, 2006, these costs are expected to be recognized over a weighted-average period of 2.7 years.

Employee Partnerships

EPE Unit I. In connection with the initial public offering of Enterprise GP Holdings in August 2005, EPE Unit I was formed to serve as an incentive arrangement for certain employees of EPCO through a profits interest in EPE Unit I. In August 2005, EPE Unit I used $51.0 million in contributions it received from its Class A limited partner (an affiliate of EPCO) to purchase 1,821,428 units of Enterprise GP Holdings. Certain EPCO employees, including all of Enterprise Products GP s executive officers other than Dan L. Duncan and Dr. Ralph S. Cunningham, were admitted as Class B limited partners of EPE Unit I without any capital contributions.

Unless otherwise agreed to by EPCO, the Class A limited partner and a majority of the Class B limited partners, EPE Unit I will be liquidated upon the earlier of (i) August 2010 or (ii) a change in control of Enterprise GP Holdings or its general partner, EPE Holdings. Upon liquidation of EPE Unit I, units having a fair market value equal to the Class A limited partner s capital base, plus any Class A preferred return for the quarter in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining units will be distributed to the Class B limited partners as a residual profits interest award in EPE Unit I.

Prior to our adoption of SFAS 123(R) in January 2006, the estimated value of the profits interest awards was accounted for in a manner similar to a stock appreciation right. Upon our adoption of SFAS 123(R), we began recognizing compensation expense based upon an estimated grant date fair value of the Class B partnership equity awards of approximately $12.4 million. As of December 31, 2006, there was $9.2 million of total unrecognized compensation cost related to these awards, of which we estimate our share to be $7.9 million. That cost is expected to be recognized on a straight-line basis through the third quarter of 2010.

The grant date fair value of the Class B limited partnership equity awards in EPE Unit I was estimated using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards ranging from four to five years, (ii) risk-free interest rates ranging from 4.0% to 4.8%, (iii) an expected distribution yield on units of Enterprise GP Holdings ranging from 3.0% to 3.7%, and (iv) an expected unit price volatility for Enterprise GP Holdings units ranging from 21.1% to 30.0%.

For the years ended December 31, 2006 and 2005, we recorded $2.1 million and $2.0 million, respectively, of non-cash compensation expense for these awards associated with employees who provide services to us.

EPE Unit II, L.P. In December 2006, EPE Unit II, L.P. (EPE Unit II) was formed to serve as an incentive arrangement for Dr. Ralph S. Cunningham, an executive officer of our general partner. The officer, who is not a participant in EPE Unit I, was granted a profits interest award in EPE Unit II. EPCO serves as the general partner of EPE Unit II.

At inception, EPE Unit II used $1.5 million in contributions it received from an affiliate of EPCO (which was admitted as the Class A limited partner of EPE Unit II as a result of such contribution) to purchase 40,725 units of Enterprise GP Holdings at an average price of $36.91 per unit in December 2006. The officer was issued a Class B limited partner interest in EPE Unit II without any capital contribution.

Unless otherwise agreed upon by EPCO, the Class A limited partner and the Class B limited partner, EPE Unit II will be liquidated upon the earlier of (i) December 2011 or (ii) a change in control of Enterprise GP Holdings or its general partner, EPE Holdings. Upon liquidation of the EPE Unit II, units having a fair market value equal to the Class A limited partner s capital base will be distributed to the Class A limited partner, plus any Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partner as a residual profits interest award in EPE Unit II.

The fair value of the Class B limited partnership equity award in EPE Unit II was estimated on the date of grant using the Black-Scholes option pricing model, which incorporated various assumptions including (i) an expected life of the award of five years, (ii) risk-free interest rate of 4.4%, (iii) an expected distribution yield on units of Enterprise GP Holdings of 3.8%, and (iv) an expected Enterprise GP Holdings unit price volatility of 18.7%.

For the year ended December 31, 2006 we recorded a nominal amount of non-cash compensation expense associated with EPE Unit II. As of December 31, 2006, there was $0.2 million of total unrecognized compensation cost related to this profits interest, of which we estimate our share to be $0.2 million. This cost is expected to be recognized on a straight-line basis through December 2010.

Note 6. Employee Benefit Plans

During the first quarter of 2005, we acquired a controlling ownership interest in Dixie, which resulted in it 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 2006 and 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 presents Dixie s benefit obligations, fair value of plan assets, unfunded liabilities and accrued benefit liabilities at December 31, 2006.

	Pension Plan	**Postretirement Plan**
Projected benefit obligation	$9,006	$ 5,311
Accumulated benefit obligation	6,625	5,311
Fair value of plan assets	7,731	
Unfunded liability	1,274	5,311
Accrued benefit liability	1,186	5,311

Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2006 were as follows: discount rate of 5.75%, expected long-term rate of return on assets of 7.00%; rate of compensation increase of 4.00%; and a medical trend rate of 9.00% for 2007 grading to an ultimate trend of 5.00% for 2010 and later years. Dixie s net pension and postretirement benefit costs for 2006 were $0.7 million and $0.3 million, respectively.

Future benefits expected to be paid from Dixie s pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	**Postretirement Plan**
2007	$ 621	$ 333
2008	526	331
2009	754	357
2010	765	395
2011	883	433
2012 through 2015	5,408	2,168
Total	$8,957	$ 4,017

On December 31, 2006, Dixie adopted the recognition and disclosure provisions of SFAS 158. SFAS 158 require Dixie to recognize the funded status of its defined benefit pension and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income.

The incremental effects of Dixie s implementation of SFAS 158 on our Consolidated Balance Sheets at December 31, 2006 are presented in the following table. Had we not been required to adopt SFAS 158 at December 31, 2006, we would have recognized an additional minimum liability pursuant to the provisions of SFAS 87.

	At December 31, 2006		
	Prior to Adopting SFAS 158	Effect of Adopting SFAS 158	As reported
Liability for Dixie benefit plans	$ 6,404	$ 751	$ 7,155
Deferred income taxes		(287)	(287)
Total liabilities	7,509,021	464	7,509,485
Accumulated other comprehensive income		(464)	(464)
Total equity	6,480,697	(464)	6,480,233

Included in Accumulated Other Comprehensive Income (AOCI) on the Consolidated Balance Sheet at December 31, 2006 are the following amounts that have not been recognized in net periodic pension costs: unrecognized transition obligation of $1.2 million ($0.7 million, net of tax), unrecognized prior service costs of $1.5 million ($0.9 million, net of tax) and unrecognized actuarial loss of $3.1 million ($1.9 million, net of tax).

Note 7. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar with respect to a recently acquired NGL marketing business located in Canada. 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 (i) variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates. 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 transaction to be hedged must be exposed to commodity, interest rate or exchange rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, (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.

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 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 interest rate borrowings under various debt agreements. We assess cash flow risk related to interest rates by (i) identifying and measuring changes in our interest rate exposures that may impact future cash flows and (ii) 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 exposure 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 it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business environment.

Fair Value Hedges Interest Rate Swaps. As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2006 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 8.89%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to7.43%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.33%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95%to 5.76%	$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 the 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, 2006, was a liability of $29.1 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2006, 2005 and 2004 reflects a $5.2 million loss, $10.8 million benefit and $9.1 million benefit from these swap agreements, respectively.

Cash Flow Hedges   Forward-Starting Interest Rate Swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swaps having an aggregate notional value of $2.0 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 $2.0 billion in principal amount of fixed-rate debt. In October 2004, the Operating Partnership issued $2.0 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 AOCI to reduce interest expense over the life of the associated debt. We reclassified $4.2 million, $4.0 million and $1.3 million from AOCI during the years ended December 31, 2006, 2005 and 2004, respectively, which reduced the amount of interest expense we recognized.

Cash Flow Hedges Treasury Locks. During the second quarter of 2006, the Operating Partnership entered into a treasury lock transaction having a notional amount of $250.0 million. In addition, in July 2006, the Operating Partnership entered into an additional treasury lock transaction having a notional amount of $50.0 million. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. The Operating Partnership s purpose of entering into these transactions was to hedge the underlying U.S. treasury rate related to its anticipated issuance of subordinated debt during the second quarter of 2006. In July 2006, the Operating Partnership issued $300.0 million in principal amount of its Junior Subordinated Notes A (see Note 14). Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. In July 2006, the Operating Partnership elected to terminate these treasury lock transactions and recognized a minimal gain.

During the fourth quarter of 2006, the Operating Partnership entered into treasury lock transactions having a notional value of $562.5 million. The Operating Partnership entered into these transactions to hedge the underlying U.S. treasury rates related to its anticipated issuances of subordinated debt during the second and fourth quarters of 2007. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. At December 31, 2006, the value of the treasury locks was $11.2 million.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain 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 price risks associated with such products, 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) the value of 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, NGLs or certain petrochemical products. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

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, 2006, 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, 2006 was a liability of $3.2 million. During the years ended December 31, 2006, 2005 and 2004, we recorded $10.3 million, $1.1 million and $0.4 million, respectively, of income related to our commodity financial instruments, which is included in operating costs and expenses on our Statements of Consolidated Operations.

Foreign Currency Hedging Program

In October 2006, we acquired all of the outstanding stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan. Since this foreign subsidiary s functional currency is the Canadian dollar, we could be adversely affected by fluctuations in foreign currency exchange rates. We attempt to hedge this risk using foreign purchase contracts to fix the exchange rate. As of December 31, 2006, we had entered into foreign purchase contracts valued at $5.1 million, all of which settled in January 2007. In January and February 2007, we entered into $3.8 million and $4.8 million, respectively, of such instruments. These contracts typically settle in the month following their inception. Due to the limited duration of these contracts, we utilize mark-to-market accounting for these transactions, the effect of which has had a minimal impact on our earnings.

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:

	At December 31, 2006		At December 31, 2005	
Financial Instruments	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents	$ 46,286	$ 46,286	$ 57,050	$ 57,050
Accounts receivable	1,323,028	1,323,028	1,454,583	1,454,583
Commodity financial instruments (1)	1,472	1,472	1,114	1,114
Financial liabilities:				
Accounts payable and accrued expenses	1,774,976	1,774,976	1,763,390	1,763,390
Fixed-rate debt (principal amount)	4,909,068	4,955,176	4,359,068	4,395,110
Variable-rate debt	420,000	420,000	507,000	507,000
Commodity financial instruments (1)	4,655	4,655	1,167	1,167
Interest rate hedging financial instruments (2)	29,060	29,060	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.

Note 8. Cumulative Effect of Changes in Accounting Principles

During the years ended December 31, 2006, 2005 and 2004, we recorded various amounts related to the cumulative effect of changes in accounting principles, including (i) a benefit of $1.5 million in January 2006 related to the implementation of SFAS 123(R), (ii) a charge of $4.2 million in December 2005 related to our implementation of FIN 47 and (iii) a combined benefit of $10.8 million during 2004 related to changing a subsidiary s accounting method for planned major maintenance activities and the method we use to account for our investment in Venice Energy Services Company, LLC (VESCO).

See Note 6 regarding the balance sheet impact of adopting SFAS 158 at December 31, 2006, which had no effect on net income.

SAB 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements,* addresses how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. This SAB requires us to quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The provisions of SAB 108 did not have a material impact on our consolidated financial statements.

Effect of Implementation of SFAS 123(R)

SFAS 123(R) requires us to recognize compensation expense related to our equity awards based on the fair value of the award at the grant date. The fair value of an equity award is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an award is amortized to earnings on a straight-line basis over the requisite service or vesting period. Previously recognized deferred compensation related to restricted units was reversed on January 1, 2006.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. See Notes 2 and 5 for additional information regarding our accounting for equity awards.

Effect of Implementation of FIN 47

In December 2005, we adopted FIN 47, which required us to record a liability for AROs in which the timing and/or amount of settlement of the obligation is uncertain. These conditional asset retirement obligations were not addressed in SFAS 143, which we adopted on January 1, 2003. We recorded a charge of $4.2 million in connection with our implementation of FIN 47, which represents the depreciation and accretion expense we would have recognized in prior periods had we recorded these conditional asset retirement obligations when incurred. See Note 10.

Effect of change from the Accrue-In-Advance Method to the Expense-As-Incurred Method for 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 accounting 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 this change was preferable under the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7.0 million.

Effect of changing from the cost method to the equity method with respect to our 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 partnerships and 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 such 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 using the cost method prior to 2004. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

The following table shows unaudited pro forma net income for the years ended December 31, 2006, 2005 and 2004, assuming these accounting changes noted above were applied retroactively to January 1, 2004.

	For the Year Ended December 31,		
	2006	2005	2004
Pro Forma income statement amounts:			
Historical net income	$601,155	$419,508	$268,261
Adjustments to derive pro forma net income:			
Effect of implementation of SFAS 123(R):			
Remove cumulative effect of change in accounting principle recorded in January 2006	(1,472)		
Additional compensation expense that would have been recorded for unit options		(708)	(932)
Remove compensation expense related to awards of profits interests in EPE Unit L.P.		1,271	
Effect of implementation of FIN 47:			
Remove cumulative effect of change in accounting principle recorded in December 2005		4,208	
Record depreciation and accretion expense associated with conditional asset retirement obligations		(735)	(373)
Effect of change from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:			
Remove cumulative effect of change in accounting principle recorded in January 2004			(7,013)
Remove minority interest expense associated with change in accounting principle Sun 33.33% portion			2,338
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			(3,768)
Remove historical dividend income recorded from VESCO			(2,136)
Record equity earnings from VESCO			2,429
Pro forma net income	599,683	423,544	258,806
Enterprise Products GP interest	(96,969)	(71,077)	(36,919)
Pro forma net income available to limited partners	$502,714	$352,467	$221,887
Pro forma per unit data (basic):			
Historical units outstanding	414,442	382,463	265,511
Per unit data:			
As reported	$ 1.22	$ 0.91	$ 0.87
Pro forma	$ 1.21	$ 0.92	$ 0.84

Pro forma per unit data (diluted):			
Historical units outstanding	414,759	382,963	266,045
Per unit data:			
As reported	$ 1.22	$ 0.91	$ 0.87
Pro forma	$ 1.21	$ 0.92	$ 0.83

Note 9. Inventories

Our inventory amounts were as follows at the dates indicated:

	At December 31,	
	2006	**2005**
Working inventory	$387,973	$279,237
Forward-sales inventory	35,871	60,369
Inventory	$423,844	$339,606

Our regular trade (or working) inventory is comprised of inventories of natural gas, NGLs, and certain petrochemical products that are available-for-sale or used by us in the provision of services. Our forward sales inventory consists of segregated NGL and natural gas volumes dedicated to the fulfillment of forward-sales contracts. Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales were $11.8 billion, $10.3 billion and $7.2 billion for the years ended December 31, 2006, 2005 and 2004, respectively.

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. 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 commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market (LCM) adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

- Write-downs of NGL inventories are recorded as a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;
- Write-downs of natural gas inventories are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and
- Write-downs of petrochemical inventories 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, 2006, 2005 and 2004, we recognized LCM adjustments of approximately $18.6 million, $21.9 million and $9.4 million, respectively. 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.

Note 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, 2006	2005
Plants and pipelines (1)	3-35(5)	$ 8,774,683	$8,209,580
Underground and other storage facilities (2)	5-35(6)	596,649	549,923
Platforms and facilities (3)	23-31	161,839	161,807
Transportation equipment (4)	3-10	27,008	24,939
Land		40,010	38,757
Construction in progress		1,734,083	854,595
Total		11,334,272	9,839,601
Less accumulated depreciation		1,501,725	1,150,577
Property, plant and equipment, net		$ 9,832,547	$8,689,024

(1) Plants and pipelines include 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 include underground product storage caverns; storage tanks; water wells; and

related assets.

(3) Platforms and facilities include 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 as follows: 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 as follows:

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, 2006, 2005 and 2004 was $350.8 million, $328.7 million and $161.0 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 in September 2004.

We capitalized $55.7 million, $22.0 million and $2.8 million of interest in connection with capital projects during the years ended December 31, 2006, 2005 and 2004, respectively.

Purchase of Pioneer Plant from TEPPCO. In March 2006, we paid $38.2 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After completing this asset purchase, we increased the capacity of the Pioneer natural gas processing plant at an additional cost of $21.0 million. This expansion was completed in July 2006 and enables us to process natural gas production from the Jonah and Pinedale fields that will be transported to our Wyoming facilities as a result of the contract rights we acquired from TEPPCO. Of the $38.2 million we paid TEPPCO to acquire the Pioneer facility, $37.8 million was allocated to the contract rights we acquired (see Note 13).

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. These purchases are part of the pipeline projects we announced in July 2006 in connection with our new long-term natural gas transportation and storage contracts with CenterPoint Energy Resources Corp. The acquired pipelines will be modified for natural gas service.

Purchase of NGL pipeline from ExxonMobil. In August 2006, we acquired a 220-mile pipeline from ExxonMobil Pipeline Company (ExxonMobil) for $97.7 million in cash. This pipeline originates in Corpus Christi, Texas and extends to Pasadena, Texas. This pipeline is a component of the DEP South Texas NGL Pipeline System, which connects our Armstrong and Shoup NGL fractionation facilities located in South Texas to our Mont Belvieu facility.

See Note 17 for information regarding our relationship with TEPPCO.

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. 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, 2005.

Asset retirement obligation liability balance, December 31, 2005	$ 16,795
Liabilities incurred	1,977
Liabilities settled	(1,348)
Revisions in estimated cash flows	5,650
Accretion expense	1,329
Asset retirement obligation liability balance, December 31, 2006	$ 24,403

Property, plant and equipment at December 31, 2006 and 2005 includes $3.0 million and $0.9 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 $1.3 million for 2007, $1.4 million for 2008, $1.5 million for 2009, $1.7 million for 2010 and $1.8 million for 2011.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2006 and 2005 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

Note 11. Investments In and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 16 for a general discussion of our business segments. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at December 31, 2006	Investments in and advances to Unconsolidated Affiliates at December 31, 2006	December 31, 2005
NGL Pipelines & Services:			
VESCO	13.1%	$ 39,618	$ 39,689
K/D/S Promix, L.L.C. (Promix)	50%	46,140	65,103
Baton Rouge Fractionators LLC (BRF)	32.3%	25,471	25,584
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company (Jonah)	14.4%	120,370	
Evangeline (1)	49.5%	4,221	3,151
Coyote Gas Treating, LLC (Coyote (2))			1,493
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (Poseidon)	36%	62,324	62,918
Cameron Highway Oil Pipeline Company (Cameron Highway)	50%	60,216	58,207
Deepwater Gateway, L.L.C. (Deepwater Gateway)	50%	117,646	115,477
Neptune (3)	25.7%	58,789	68,085
Nemo Gathering Company, LLC (Nemo)	33.9%	11,161	12,157
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (BRPC)	30%	13,912	15,212
La Porte (4)	50%	4,691	4,845
Total		$564,559	$471,921

(1) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

(2) We sold our 50% interest in Coyote in August 2006 and recorded a net gain on the sale of $3.3 million.

(3)

In 2006, we recorded a $7.4 million non-cash impairment charge attributable to our investment in Neptune.

(4) 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 a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At December 31, 2006 and 2005, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost amounts totaling $38.7 million and $48.1 million, respectively, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, 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. Amortization of such excess cost amounts was $2.1 million, $2.3 million and $1.9 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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The following table presents our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31, 2006	2005	2004
NGL Pipelines & Services:			
Dixie [(1)]	$	$ 1,103	$ 1,273
VESCO [(2)]	1,719	1,412	6,132
Belle Rose [(1)]		(151)	(402)
Promix	1,353	1,876	859
BRF	2,643	1,313	2,190
Tri-States [(1)]			(154)
Onshore Natural Gas Pipelines & Services:			
Evangeline	958	331	231
Coyote	1,676	2,053	541
Jonah	238		
Offshore Pipelines & Services:			
Poseidon	11,310	7,279	2,509
Cameron Highway [(3)]	(11,000)	(15,872)	(461)
Deepwater Gateway	18,392	10,612	3,562
Neptune [(4)]	(8,294)	2,019	(1,852)
Nemo	1,501	1,774	1,628
Starfish Pipeline Company, LLC (Starfish[(5)])		313	3,473
Petrochemical Services:			
BRPC	1,864	1,224	1,943
La Porte	(795)	(738)	(710)
Other:			
GulfTerra GP [(6)]			32,025
Total	$ 21,565	$ 14,548	$52,787

(1) We acquired additional ownership interests in or control over these entities since January 1, 2004 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: Dixie, February 2005; Belle Rose, June 2005; and Tri-States, April 2004.

(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.

(3) 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).

(4) Equity earnings from Neptune for 2006 include a $7.4 million non-cash impairment charge.

(5)

We were required under a consent decree published for comment by the U.S. Federal Trade Commission 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, 2006, 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 facility and related 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 50.0% 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, 2006	2005
BALANCE SHEET DATA:		
Current assets	$ 62,138	$ 72,784
Property, plant and equipment, net	242,083	328,270
Other assets	12,189	12,471
Total assets	$316,410	$413,525
Current liabilities	$ 30,686	$ 32,886
Other liabilities	8,117	7,343
Combined equity	277,607	373,296
Total liabilities and combined equity	$316,410	$413,525

	For the Year Ended December 31, 2006	2005	2004
INCOME STATEMENT DATA:			
Revenues	$190,320	$207,775	$244,521
Operating income (loss)	(26,885)	6,696	40,259
Net income (loss)	(25,543)	6,509	40,355

Onshore Natural Gas Pipelines & Services

At December 31, 2006, 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 located in south Louisiana. A subsidiary of Acadian Gas, LLC owns the Evangeline interests, which were contributed to Duncan Energy Partners in February 2007 in connection with its initial public offering (see Note 17).

Coyote. We owned a 50.0% interest in Coyote during 2005 and 2004, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado. During 2006, we sold our interest in Coyote and recorded a gain on the sale of $3.3 million.

Jonah. At December 31, 2006, we owned an approximate 14.4% interest in Jonah, which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. Upon completion of the Jonah Phase V expansion project in 2007, we expect to own an approximate 20% equity interest in Jonah, with TEPPCO owning the remaining 80%. Our equity interest in Jonah at December 31, 2006 is based on capital contributions we made to Jonah in connection with its Phase V expansion project through this date. See Note 17 for additional information regarding our Jonah affiliate.

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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, 2006	At December 31, 2005
BALANCE SHEET DATA:		
Current assets	$ 65,048	$ 36,118
Property, plant and equipment, net	639,641	36,380
Other assets	192,027	33,950
Total assets	$896,716	$106,448
Current liabilities	$ 49,708	$ 72,498
Other liabilities	28,802	32,737
Combined equity	818,206	1,213
Total liabilities and combined equity	$896,716	$106,448

	For the Year Ended December 31, 2006	2005	2004
INCOME STATEMENT DATA:			
Revenues	$372,240	$347,561	$257,957
Operating income	48,387	9,142	8,971
Net income	40,608	4,668	4,657

Offshore Pipelines & Services

At December 31, 2006, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36.0% 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 50.0% 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 50.0% interest in Deepwater Gateway, which owns the Marco Polo platform located in the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Ghengis 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 and Nautilus Systems, 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 to sell our ownership interest in Starfish by March 31, 2005. 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.

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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, 2006	At December 31, 2005
BALANCE SHEET DATA:		
Current assets	$ 56,689	$ 141,756
Property, plant and equipment, net	1,178,811	1,201,926
Other assets	10,108	7,961
Total assets	$1,245,608	$1,351,643
Current liabilities	$ 22,043	$ 120,611
Other liabilities	510,773	511,633
Combined equity	712,792	719,399
Total liabilities and combined equity	$1,245,608	$1,351,643

	For the Year Ended December 31, 2006	2005	2004
INCOME STATEMENT DATA:			
Revenues	$153,996	$154,297	$88,603
Operating income	71,977	78,027	46,938
Net income	42,732	29,086	38,473

Neptune owns the Manta Ray Offshore Gathering System (Manta Ray) and Nautilus Pipeline System (Nautilus). Manta Ray gathers natural gas originating 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 the Nautilus pipeline. Nautilus connects our Manta Ray pipeline to our Neptune natural gas processing plant located in south Louisiana. Due to a recent decrease in throughput volumes on the Manta Ray and Nautilus pipelines, we evaluated our 25.7% investment in Neptune for impairment during the third quarter of 2006. The decrease in throughput volumes is primarily due to underperformance of certain fields, natural depletion and hurricane-related delays in starting new production. These factors contributed to significant delays in throughput volumes Neptune expects to receive. As a result, Neptune has experienced operating losses in recent periods.

At December 31, 2005, the carrying value of our investment in Neptune was $68.1 million, which included $10.9 million of excess cost related to its original acquisition in 2001. Our review of Neptune s estimated cash flows during the third quarter of 2006 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.4 million. This loss is recorded as a component of Equity in income of unconsolidated affiliates in our Statement of Consolidated Operations for the year ended December 31, 2006. After recording this impairment charge, the carrying value of our investment in Neptune at December 31, 2006 was $58.8 million.

Our investment in Neptune was written down to fair value, which management estimated using recognized business valuation techniques. The fair value analysis is based upon management s expectation of future cash flows, which incorporates certain industry information and assumptions made by management. For example, the review of Neptune included management estimates regarding natural gas reserves of producers served by Neptune. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result in the future.

Petrochemical Services

At December 31, 2006, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30.0% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50.0% 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, 2006	At December 31, 2005
BALANCE SHEET DATA:		
Current assets	$ 3,324	$ 5,508
Property, plant and equipment, net	51,159	54,751
Total assets	$54,483	$60,259
Current liabilities	$ 832	$ 1,178
Other liabilities	2	1
Combined equity	53,649	59,080
Total liabilities and combined equity	$54,483	$60,259

	For the Year Ended December 31, 2006	2005	2004
INCOME STATEMENT DATA:			
Revenues	$19,014	$16,849	$18,378
Operating income	4,626	2,606	5,131
Net income	4,729	2,650	5,151

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 $425.0 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 business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

Note 12. Business Combinations

Transactions Completed during the Year Ended December 31, 2004

Our expenditures for business combinations during the year ended December 31, 2004 were $4.1 billion, which includes consideration paid or granted to complete the GulfTerra Merger in September 2004.

GulfTerra Merger and Related Transactions. On September 30, 2004, we completed the merger of GulfTerra with a wholly owned subsidiary of ours. In addition, we 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 ours.

The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4.0 billion. In connection with closing the merger transactions, the Operating

Partnership borrowed an aggregate $2.8 billion under its credit facilities to fund our cash payment obligations of the GulfTerra Merger and to finance tender offers for GulfTerra s outstanding senior and senior subordinated notes.

In connection with the GulfTerra Merger, we were required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline, and an undivided 50% interest in a Mississippi propane storage facility. We completed the sale of the storage facility in December 2004 and the sale of our investment in Starfish in March 2005. 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.

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.

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 from El Paso was September 1, 2004. As a result, our Statements of Consolidated Operations for the year ended December 31, 2004 include four months of earnings from the South Texas midstream assets. Our fiscal 2006 and 2005 results already reflect the businesses we acquired in connection with the GulfTerra Merger; therefore, no pro forma presentation of these two periods is required.

Given the GulfTerra Merger s significance to us, the following table presents selected pro forma earnings information for the year ended December 31, 2004 as if the GulfTerra Merger and related transactions had been completed on January 1, 2004 instead of September 30, 2004. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. 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 January 1, 2004. The amounts shown in the following table are in millions, except per unit amounts.

		For Year Ended December 31, 2004
Pro forma earnings data:		
Revenues	$	9,615
Costs and expenses	$	9,067
Operating income	$	576
Net income	$	335
Basic earnings per unit (EPU):		
Units outstanding, as reported		265
Units outstanding , pro forma		378
Basic EPU, as reported	$	0.87
Basic EPU, pro forma	$	0.75
Diluted EPU:		
Units outstanding, as reported		266
Units outstanding , pro forma		379

Diluted EPU, as reported	$	0.87
Diluted EPU, pro forma	$	0.75

Other Transactions. In addition to the GulfTerra Merger, our business combinations during 2004 included the purchase of (i) an additional 16.7% ownership interest in Tri-States for $16.5 million, (ii) an additional 10% ownership interest in Seminole for $28 million and (iii) the remaining 33.3% ownership interest in BEF for $13.4 million.

Transactions Completed during the Year Ended December 31, 2005

Our expenditures for business combinations during the year ended December 31, 2005 were $326.6 million, which included $8.3 million of purchase price adjustments relating to transactions that occurred prior to 2005. Due to the immaterial nature of our 2005 business combinations, our pro forma basic and diluted earnings per unit amounts for 2005 are practically the same as our actual basic and diluted earnings per unit amounts for 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 $25.0 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 $7.0 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.

Transactions Completed during the Year Ended December 31, 2006

Our expenditures for business combinations during the year ended December 31, 2006 were $276.5 million.

Encinal Acquisition. On July 1, 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts that comprised the South Texas natural gas transportation and processing business of an affiliate of Lewis Energy Group, L.P. (Lewis). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the Encinal acquisition) was $326.3 million, which consisted of $145.2 million in cash and 7,115,844 of our common units.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas wells producing from the Olmos and Wilcox formations. The Encinal system consists of 452 miles of pipeline, which is comprised of 280 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing Texas Intrastate System and are processed by our South Texas natural gas processing plants.

The Encinal and Canales gathering systems will be supported by a life of reserves gathering and processing dedication by Lewis related to its natural gas production from the Olmos formation. In addition, we entered into a 10-year agreement with Lewis for the transportation of natural gas treated at its proposed Big Reef facility. This facility will treat natural gas from the southern portion of the Edwards Trend in South Texas. We also entered into a 10-year agreement with Lewis for the gathering and processing of rich gas it produces from below the Olmos formation.

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The total consideration we paid or granted to Lewis in connection with the Encinal acquisition is as follows:

Cash payment to Lewis	$ 145,197
Fair value of our 7,115,844 common units issued to Lewis	181,112
Total consideration	$ 326,309

In accordance with purchase accounting, the value of our common units issued to Lewis was based on the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. For purposes of this calculation, the average closing price was $25.45 per unit.

Since the closing date of the Encinal acquisition was July 1, 2006, our Statements of Consolidated Operations do not include any earnings from these assets prior to this date. Given the relative size of the Encinal acquisition to our other business combination transactions during 2006, the following table presents selected pro forma earnings information for the years ended December 31, 2006 and 2005 as if the Encinal acquisition had been completed on January 1, 2006 and 2005, respectively, instead of July 1, 2006. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Encinal acquisition actually occurred on January 1, 2005. The amounts shown in the following table are in millions, except per unit amounts.

	For the Year Ended December 31,	
	2006	**2005**
Pro forma earnings data:		
Revenues	$ 14,066	$ 12,408
Costs and expenses	$ 13,228	$ 11,758
Operating income	$ 859	$ 664
Net income	$ 598	$ 418
Basic earnings per unit (EPU):		
Units outstanding, as reported	414	382
Units outstanding , pro forma	422	389
Basic EPU, as reported	$ 1.22	$ 0.91
Basic EPU, pro forma	$ 1.19	$ 0.89
Diluted EPU:		
Units outstanding, as reported	415	383
Units outstanding , pro forma	422	390
Diluted EPU, as reported	$ 1.22	$ 0.91

Diluted EPU, pro forma	$ 1.19	$ 0.89

Piceance Creek Acquisition. On December 27, 2006, one of our affiliates, Enterprise Gas Processing, LLC, purchased a 100% interest in Piceance Creek Pipeline, LLC (Piceance Creek), for cash consideration of $100.0 million. Piceance Creek was wholly owned by EnCana Oil & Gas (EnCana).

The assets of Piceance Creek consist of a recently constructed 48-mile natural gas gathering pipeline, the Piceance Creek Gathering System, located in the Piceance Basin of northwestern Colorado. The Piceance Creek Gathering System has a transportation capacity of 1.6 billion cubic feet per day (Bcf/d) of natural gas and extends from a connection with EnCana s Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.5 Bcf/d Meeker natural gas treating and processing complex, which is currently under construction. Connectivity to EnCana s Great Divide Gathering System will provide the Piceance Creek Gathering System with access to production from the southern portion of the Piceance basin, including production from EnCana s Mamm Creek field. The Piceance Creek Gathering System was placed in service in January 2007 and began transporting initial volumes of approximately 300 million cubic feet per day (MMcf/d) of natural gas. We expect natural gas transportation volumes to increase to approximately 625 MMcf/d by the end of 2007, with a significant portion of these volumes being produced by EnCana, one of the largest natural gas producers in the region. In conjunction with our acquisition of Piceance Creek, EnCana signed a long-term, fixed fee gathering agreement with us and dedicated significant production to the Piceance Creek Gathering System for the life of the associated lease holdings.

Our preliminary allocation of this acquisition s purchase price was as follows: (i) $91.5 million allocated to property, plant and equipment and (ii) $8.5 million to identifiable intangible assets. See Note 13 for additional information regarding the Piceance Creek intangible assets. Since this transaction closed at year-end, our preliminary purchase price allocation is based on estimates and is subject to change when actual values are determined.

Other Transactions. In addition to the Encinal and Piceance Creek acquisitions, our business combinations during 2006 included the purchase of (i) an additional 8.2% ownership interest in Dixie for $12.9 million, (ii) all capital stock of an affiliated NGL marketing company located in Canada from related parties for $17.7 million (see Note 17) and (iii) a storage business in Flagstaff, Arizona for $0.7 million.

Purchase Price Allocation for 2006 Transactions

Our 2006 business combinations were accounted for using the purchase method of accounting and, accordingly, their cost has been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocations for these transactions during 2007.

	Encinal Acquisition	Piceance Creek Acquisition	Other	Total
Assets acquired in business combination:				
Current assets	$ 218	$	$ 36,080	$ 36,298
Property, plant and equipment, net	100,310	91,540	12,369	204,219
Investments in and advances to unconsolidated affiliates				
Intangible assets	132,872	8,460		141,332
Other assets				
Total assets acquired	233,400	100,000	48,449	381,849
Liabilities assumed in business combination:				
Current liabilities	(2,149)		(18,836)	(20,985)
Long-term debt				
Other long-term liabilities	(108)		(175)	(283)
Minority interest			1,865	1,865
Total liabilities assumed	(2,257)		(17,146)	(19,403)
Total assets acquired less liabilities assumed	231,143	100,000	31,303	362,446
Total consideration given	326,309	100,000	31,303	457,612
Goodwill	$ 95,166	$	$	$ 95,166

Of the $326.3 million in consideration we paid or granted to effect the Encinal acquisition, $95.2 million has been assigned to goodwill. Management attributes this goodwill to potential future benefits we expect to realize from our other South Texas processing and NGL businesses as a result of the Encinal acquisition. Specifically, the long-term dedication rights we acquired in connection with the Encinal acquisition are expected to improve earnings from our South Texas processing facilities and related NGL businesses due to increased volumes. See Note 13, for additional information regarding our intangible assets and goodwill.

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Note 13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	At December 31, 2006			At December 31, 2005		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carryi Valu
GL Pipelines & Services:						
ell Processing Agreement	$ 206,216	$ (67,204)	$ 139,012	$ 206,216	$ (56,157)	$150,0
cinal gas processing customer relationship	127,119	(6,049)	121,070			
MA and GulfTerra NGL Business customer relationships (1)	49,784	(12,980)	36,804	49,784	(7,829)	41,9
neer gas processing contracts	37,752		37,752			
rkham NGL storage contracts (1)	32,664	(9,800)	22,864	32,664	(5,444)	27,2
ca-Western contracts	31,229	(7,156)	24,073	31,229	(5,595)	25,6
eance Creek customer relationship	8,460		8,460			
her	35,370	(7,455)	27,915	35,370	(4,460)	30,9
gment total	528,594	(110,644)	417,950	355,263	(79,485)	275,7
shore Natural Gas Pipelines & Services:						
n Juan Gathering System customer relationships (1)	331,311	(52,318)	278,993	331,311	(30,065)	301,2
al & Hattiesburg natural gas storage contracts (1)	100,499	(19,337)	81,162	100,499	(10,742)	89,7
her	31,741	(5,747)	25,994	25,988	(3,148)	22,8
gment total	463,551	(77,402)	386,149	457,798	(43,955)	413,8
fshore Pipelines & Services:						
fshore pipeline & platform customer relationships (1)	205,845	(54,636)	151,209	205,845	(32,480)	173,3
her	1,167		1,167	1,167		1,1
gment total	207,012	(54,636)	152,376	207,012	(32,480)	174,5
rochemical Services:						
nt Belvieu propylene fractionation contracts	53,000	(7,445)	45,555	53,000	(5,931)	47,0
her	3,674	(1,749)	1,925	3,674	(1,270)	2,4
gment total	56,674	(9,194)	47,480	56,674	(7,201)	49,4
al all segments	$1,255,831	$(251,876)	$1,003,955	$1,076,747	$(163,121)	$913,6

(1) Acquired in connection with the GulfTerra Merger and related transactions in

September 2004.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Year Ended December 31,		
	2006	**2005**	**2004**
NGL Pipelines & Services	$31,159	$26,350	$16,000
Onshore Natural Gas Pipelines & Services	33,447	35,080	8,875
Offshore Pipelines & Services	22,156	25,515	6,965
Petrochemical Services	1,993	1,993	1,973
Total all segments	$88,755	$88,938	$33,813

Based on information currently available, we estimate that amortization expense associated with existing intangible assets will approximate $91.6 million in 2007, $88.1 million in 2008, $82.1 million in 2009, $77.3 million in 2010 and $71.6 million in 2011.

In general, our intangible assets fall within two categories contract-based intangible assets and customer relationships. Contract-based intangible assets represent commercial rights we acquired in connection with business combinations or asset purchases. Customer relationship intangible assets represent customer bases that we acquired in connection with business combinations and asset purchases. The values assigned to intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

We acquired $141.3 million of intangible assets during the year ended December 31, 2006, primarily attributable to customer relationships we acquired in connection with the Encinal acquisition. We acquired $743.3 million of intangible assets during the year ended December 31, 2004 in connection with the GulfTerra Merger and related transactions.

The $132.9 million of intangible assets we acquired in connection with the Encinal acquisition (see Note 12) represents the value we assigned to customer relationships, particularly the long-term relationship we now have with Lewis through natural gas processing and gathering arrangements. We recorded $127.1 million in our NGL Pipelines & Services segment associated with processing arrangements and $5.8 million in our Onshore Natural Gas Pipelines & Services segment associated with gathering arrangements. These intangible assets will be amortized to earnings over a 20-year life using methods that closely resemble the pattern in which we estimate the depletion of the underlying natural gas resources to occur.

We acquired numerous 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 GulfTerra and the 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 to provide storage services for natural gas and NGLs that GulfTerra had entered into prior to the merger.

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 (iv) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets we acquired in connection with the GulfTerra Merger 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.

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 purchase 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.

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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, 2006	At December 31, 2005
NGL Pipelines & Services		
GulfTerra Merger	$ 23,854	$ 23,927
Acquisition of Indian Springs natural gas processing business	13,162	13,180
Encinal acquisition	95,166	
Other	20,413	17,853
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	279,956	280,812
Acquisition of Indian Springs natural gas gathering business	2,165	2,185
Offshore Pipelines & Services		
GulfTerra Merger	82,135	82,386
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation business	73,690	73,690
Total	$590,541	$494,033

Goodwill recorded in connection with 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 could develop (such as reduced general and administrative costs and interest savings) that would result in improved financial results for the merged entity. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies in the United States, serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

In 2006, the only significant change in goodwill was the recording of $95.2 million in connection with our preliminary purchase price allocation for the Encinal acquisition. Management attributes this goodwill to potential future benefits we may realize from our other south Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our south Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL Pipelines & Services business segment due to management s belief that such future benefits will accrue to businesses classified within this segment.

The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our purchase of a propylene fractionation business in February 2002 and our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing business in January 2005.

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Note 14. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	At December 31, 2006	2005
Operating Partnership senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011 (1)	$ 410,000	$ 490,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
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 (2)	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	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	17,000
Other, 8.75% fixed-rate, due June 2010 (3)	5,068	5,068
Total principal amount of senior debt obligations	4,779,068	4,866,068
Operating Partnership Junior Subordinated Notes A, due August 2066	550,000	
Total principal amount of senior and junior debt obligations	5,329,068	4,866,068
Other, including unamortized discounts and premiums and changes in fair value (4)	(33,478)	(32,287)
Long-term debt	$5,295,590	$4,833,781
Standby letters of credit outstanding	$ 49,858	$ 33,129

(1) In June 2006, the Operating Partnership executed a second amendment (the Second Amendment) to the credit agreement governing its Multi-Year Revolving Credit Facility.

The Second Amendment, among other things, extends the maturity date of amounts borrowed under the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.25 billion of the commitments. Borrowings with respect to the remaining $48.0 million in commitments mature in October 2010.

(2) In accordance with SFAS 6, *Classification of Short-Term Obligations Expected to be Refinanced*, long-term and current maturities of debt reflects the classification of such obligations at December 31, 2006. With respect to Senior Notes E due in October 2007, the Operating Partnership has the ability to use available credit capacity under its Multi-Year Revolving

Credit Facility to fund the repayment of this debt.

(3) Represents remaining debt obligations assumed in connection with the GulfTerra Merger.

(4) The December 31, 2006 amount includes $29.1 million related to fair value hedges and a net $4.4 million in unamortized discounts and premiums. The December 31, 2005 amount includes $19.2 million related to fair value hedges and a net $13.1 million in unamortized discounts and premiums.

Letters of credit

At December 31, 2006 and 2005, we had $49.9 million and $33.1 million, respectively, in standby letters of credit outstanding, all of which were issued under the Operating Partnership s Multi-Year Revolving Credit Facility. As of February 2, 2007, our standby letters of credit outstanding were reduced to $37.9 million.

Parent-Subsidiary guarantor relationships

We act as guarantor of the debt obligations of our 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 we guarantee, we would be responsible for full repayment of that obligation.

Our 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 74.2% 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

Multi-Year Revolving Credit Facility. In August 2004, our 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 June 2006, our Operating Partnership amended the terms of this credit agreement a second time. The second amendment, among other things, extends the maturity date of the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.25 billion of the commitments. Borrowings with respect to $48.0 million in commitments mature in 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. We have 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 (i) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus $^1/2$% or (ii) a Eurodollar rate plus an applicable margin or (iii) a Competitive Bid Rate.

This revolving credit agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. The second amendment modified these financial covenants to, among other things, allow the Operating Partnership to include in the calculation of its Consolidated EBITDA (as defined in the credit agreement) pro forma adjustments for significant capital projects. In addition, the second amendment allows for the issuance of hybrid debt securities, such as the $550.0 million in principal amount of Junior Subordinated Notes A issued by the Operating Partnership during the third quarter of 2006.

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.

In March 2006, we generated net proceeds of $430.0 million in connection with the sale of 18,400,000 of our common units in an underwritten equity offering. In addition, in September 2006, we generated net proceeds of $320.8 million in connection with the sale of 12,650,000 of our common units in an underwritten equity offering. Subsequently, these amounts were contributed to the Operating Partnership, which primarily used such proceeds to temporarily reduce debt outstanding under its Multi-Year Revolving Credit Facility. See Note 15 for additional information regarding our equity offerings during 2006.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant in 2000, 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 us 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 our credit rating at

Standard & Poor s declining below BBB-, 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, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Senior Notes B through K. These fixed-rate notes are unsecured obligations of our 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. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to Enterprise Products GP.

Senior Notes B through D are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict our 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 an acquisition-related 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 a senior note obligation that 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 we filed in March 2005 (see Note 15).

Junior Subordinated Notes A. In the third quarter of 2006, the Operating Partnership sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 (Junior Subordinated Notes A). The Operating Partnership used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Operating Partnership s payment obligations under Junior Subordinated Notes A are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). We guaranteed the Operating Partnership s repayment of amounts due under Junior Subordinated Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Subordinated Notes A allows the Operating Partnership to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Subordinated Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the indenture agreement has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, neither we nor the Operating Partnership cannot declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinated to the Junior Subordinated Notes A.

The Junior Subordinated Notes A will bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, commencing in February 2007. After August 2016, the Junior Subordinated Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Subordinated Notes A mature in August 2066 and are not redeemable by the Operating Partnership prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Subordinated Notes A, the Operating Partnership entered into a Replacement Capital Covenant in favor of the covered debt holders (as defined in the underlying documents) pursuant to which the Operating Partnership agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the of issuance of certain securities.

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. In accordance with GAAP, we consolidate the debt of Dixie with that of our own; however we do not have the obligation to make interest or debt payments with respect to Dixie s debt. Dixie s debt obligations consist of a senior, unsecured revolving credit facility having a borrowing capacity of $28.0 million. The maturity date of this facility was extended from June 2007 to June 2010 in August 2006.

As defined in the Dixie 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 plus $^1/2$%.

The 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.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2006 and 2005.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2006.

	Range of interest rates paid	**Weighted-average interest rate paid**
Operating Partnership s Multi-Year Revolving Credit Facility	4.87% to 8.25%	5.66%
Dixie Revolving Credit Facility	4.67% to 5.79%	5.36%

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Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2007	$
2008	
2009	500,000
2010	569,068
2011	1,360,000
Thereafter	2,900,000
Total scheduled principal payments	$ 5,329,068

In accordance with SFAS 6, long-term and current maturities of debt reflect the classification of such obligations at December 31, 2006. With respect to the $500.0 million in principal due under Senior Notes E in October 2007, the Operating Partnership has the ability to use available credit capacity under its Multi-Year Revolving Credit Facility to fund the repayment of this debt. The preceding table and our Consolidated Balance Sheet at December 31, 2006 reflect this ability to refinance.

Debt Obligations of Unconsolidated Affiliates

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2006, (ii) total debt of each unconsolidated affiliate at December 31, 2006 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2007	2008	2009	2010	2011	After 2011
Cameron Highway	50%	$415,000	$	$25,000	$25,000	$50,000	$ 55,000	$260,000
Poseidon	36%	91,000					91,000	
Evangeline	49.5%	25,650	5,000	5,000	5,000	10,650		
Total		$531,650	$5,000	$30,000	$30,000	$60,650	$146,000	$260,000

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at December 31, 2006. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2006:

Cameron Highway. In December 2005, Cameron Highway issued $415.0 million of private placement, non-recourse senior secured notes due December 2017. The senior secured notes were issued in two series $365.0 million of Series A notes, which bear interest at a fixed annual rate of 5.86%, and $50.0 million of Series B notes, which charge variable interest based on a Eurodollar rate plus 1%. At December 31, 2006, the variable interest rate charged under the Series B notes was 6.18%.

The Series A and B 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 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 respective 50% ownership interests in Cameron Highway, and (iv) letters of credit in an amount of $36.8 million each issued by our 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.

In March 2006, Cameron Highway amended the note purchase agreement governing its Series A and B notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays. In general, this amendment modified certain financial covenants in light of production forecasts made by management. Also, the amendment specifies that Cameron Highway cannot make distributions to its partners until the earlier of (i) December 31, 2007 or (ii) the date on which Cameron Highway s debt service coverage ratios are equal to or greater than 1.5 to 1 for three consecutive fiscal quarters. In order for Cameron Highway to resume paying distributions to its partners, no default or event of default can be present or continuing at the date Cameron Highway desires to start paying such distributions.

Poseidon. Poseidon has a $150.0 million revolving credit facility that matures in May 2011. 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, 2006 and 2005 were 6.68% and 5.34%, respectively.

Evangeline. At December 31, 2006, long-term debt for Evangeline consisted of (i) $18.2 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 $5.0 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 noteholders 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 $^1/2$%. The variable interest rates charged on this note at December 31, 2006 and 2005 were 6.08% and 4.23%, respectively. Accrued interest payable related to the subordinated note was $7.9 million and $7.1 million at December 31, 2006 and 2005, respectively.

Note 15. Partners Equity and Distributions

Our common units 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 our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the Partnership Agreement). We are managed by our general partner, Enterprise Products GP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our 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.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

In August 2005, we revised our Partnership Agreement to allow Enterprise Products GP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2% general partner interest would be proportionately reduced. At the time of such offerings, Enterprise Products GP has historically contributed cash to us to maintain its 2% general partner interest. Enterprise Products GP made such cash contributions to us during the years ended December 31, 2006 and 2005. If Enterprise Products GP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, Enterprise Products GP can, under certain conditions, restore its full 2% general partner interest by making additional cash contributions to us.

Equity offerings and registration statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by Enterprise Products GP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

In March 2005, we filed a universal shelf registration statement with the U.S. Securities and Exchange Commission (SEC) registering the issuance of up to $4.0 billion of additional equity and debt securities. After taking into account past issuance of securities under this registration statement, we have the ability to issue approximately $2.1 billion of additional securities under this registration statement as of December 31, 2006.

During 2003, we instituted a distribution reinvestment plan (DRIP). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. We have a registration statement on file with the SEC authorizing the issuance of up to 15,000,000 common units in connection with the DRIP. A total of 14,179,097 common units have been issued under this registration statement through December 31, 2006. We expect to file a registration statement in 2007 to increase the number of common units authorized for issuance under this plan.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 362,686 common units have been issued to employees under this plan through December 31, 2006.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the years ended December 31, 2006, 2005 and 2004:

		Net Proceeds from Sale of Common Units		
	Number of common units issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
Fiscal 2004:				
Underwritten offerings	34,500,000	$680,390	$ 13,886	$694,276
Other offerings, primarily DRIP	5,183,591	109,368	2,231	111,599
Total 2004	39,683,591	$789,758	$ 16,117	$805,875
Fiscal 2005:				
Underwritten offerings	21,250,000	$544,347	$ 11,109	$555,456
Other offerings, primarily DRIP	2,729,740	68,269	1,393	69,662
Total 2005	23,979,740	$612,616	$ 12,502	$625,118
Fiscal 2006:				

Underwritten offerings	31,050,000	$735,819	$ 15,003	$750,822
Other offerings, primarily DRIP	3,774,649	95,006	1,940	96,946
Total 2006	34,824,649	$830,825	$ 16,943	$847,768

Net proceeds received from our underwritten offerings completed during 2004 were generally used to (i) repay a $225.0 million acquisition credit facility related to the GulfTerra Merger, (ii) partially fund our payment obligations under the GulfTerra Merger and (iii) temporarily reduce borrowings outstanding under the Multi-Year Revolving Credit Facility. Net proceeds from our other offerings were used for general partnership purposes.

Other offerings primarily represents the issuance of common units under our distribution reinvestment plan (DRIP). Net proceeds received from our underwritten offerings completed during 2005 were generally used to repay an interim credit facility related to the GulfTerra Merger and to temporarily reduce borrowings outstanding under the Multi-Year Revolving Credit Facility. Net proceeds from our other offerings were used for general partnership purposes.

Net proceeds received from our underwritten and other offerings completed during 2006 were used to temporarily reduce borrowings outstanding under the Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2003:

	Common Units	Restricted Common Units	Class B Special Units	Treasury Units
Balance, December 31, 2003	213,366,760		4,413,549	798,313
Units issued in connection with underwritten offerings	34,500,000			
Units issued in connection with other offerings	5,200,078			
Units issued in connection with equity-based awards		434,225		
Reissuance of treasury units to satisfy exercise of options	371,113			(371,113)
Conversion of Class B special units to common units	4,413,549		(4,413,549)	
Units issued in connection with GulfTerra Merger (see Note 12)	104,495,523	54,300		
Conversion of Series F2 units to common units	1,950,317			
Balance, December 31, 2004	364,297,340	488,525		427,200
Units issued in connection with underwritten offerings	21,250,000			
Units issued in connection with other offerings	2,729,740			
Units issued in connection with equity-based awards	826,000	362,011		
Forfeiture of restricted units		(92,448)		
Conversion of restricted units to common units	6,484	(6,484)		
Cancellation of treasury units				(427,200)
Balance, December 31, 2005	389,109,564	751,604		
Units issued in connection with underwritten offerings	31,050,000			

Units issued in connection with other offerings	3,774,649	
Units issued in connection with equity-based awards	211,000	466,400
Forfeiture of restricted units		(70,631)
Conversion of restricted units to common units	42,136	(42,136)
Units issued in connection with Encinal acquisition	7,115,844	
Balance, December 31, 2006	431,303,193	1,105,237

Summary of Changes in Limited Partners Equity

The following table details the changes in limited partners equity since December 31, 2003:

	Common units	Restricted Common units	Class B Special units	Total
Balance, December 31, 2003	$1,582,951	$	$100,182	$1,683,133
Net income	229,016	142	1,995	231,153
Operating leases paid by EPCO	7,449	2	100	7,551
Cash distributions to partners	(390,928)	(218)	(3,288)	(394,434)
Unit option reimbursements to EPCO	(3,813)			(3,813)
Net proceeds from sales of common units	789,758			789,758
Proceeds from conversion of Series F2 convertible units to common units	38,800			38,800
Proceeds from exercise of unit options	398			398
Conversion of Class B special units to common units	98,993		(98,993)	
Value of equity interests granted to complete the GulfTerra Merger	2,851,796	2,479		2,854,275
Other issuance of restricted units		9,922		9,922
Treasury units reissued to satisfy unit options	520		4	524
Balance, December 31, 2004	5,204,940	12,327		5,217,267
Net income	347,948	564		348,512
Operating leases paid by EPCO	2,067	3		2,070
Cash distributions to partners	(629,629)	(931)		(630,560)
Unit option reimbursements to EPCO	(9,199)			(9,199)
Net proceeds from sales of common units	612,616			612,616
Proceeds from exercise of unit options	21,374			21,374
Issuance of restricted units		9,478		9,478
Vesting of restricted units	143	(143)		
Forfeiture of restricted units		(2,663)		(2,663)
Amortization of equity-based awards	1,355	3		1,358
Cancellation of treasury units	(8,915)			(8,915)
Balance, December 31, 2005	5,542,700	18,638		5,561,338
Net income	502,969	1,187		504,156
Operating leases paid by EPCO	2,062	5		2,067
Cash distributions to partners	(738,004)	(1,628)		(739,632)
Unit option reimbursements to EPCO	(1,818)			(1,818)
Net proceeds from sales of common units	830,825			830,825
Common units issued in connection with Encinal acquisition	181,112			181,112
Proceeds from exercise of unit options	5,601			5,601
Amortization of equity-based awards	2,209	6,073		8,282
Change in accounting method for equity Awards (see Note 5)	(896)	(14,919)		(15,815)

Acquisition-related disbursement of cash	(6,183)	(16)		(6,199)
Balance, December 31, 2006	$6,320,577	$ 9,340	$	$6,329,917

In October 2006, we acquired all of the capital stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan for $17.7 million in cash. The amount we paid for this business exceeded the carrying values of the assets acquired and liabilities assumed from this related party (which is under common control with us) by $6.3 million, of which $6.2 million was allocated to limited partners and $0.1 million to our general partner. The excess of the acquisition price over the net book value of this business at the time of acquisition is treated as a deemed distribution to our owners and presented as an Acquisition-related disbursement of cash in our Statement of Partners Equity for the year ended December 31, 2006. The total purchase price is a component of Cash used for business combinations as presented in our Statement of Consolidated Cash Flows for the year ended December 31, 2006 (see Note 12).

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Units issued in connection with the GulfTerra Merger. In conjunction with the GulfTerra Merger (see Note 12), we issued 1.81 of our common units for each GulfTerra common unit (including GulfTerra s restricted common units) remaining after our purchase of 2,876,620 GulfTerra common units owned by El Paso. The number of units we issued in connection with this conversion was calculated as follows:

GulfTerra units outstanding at September 30, 2004:		
Common units, including time-vested restricted common units		60,638,989
Series C units		10,937,500
Total historical units outstanding at September 30, 2004		71,576,489
Adjustments to GulfTerra historical units outstanding as a result of the GulfTerra Merger:		
Purchase of GulfTerra Series C units from El Paso		(10,937,500)
Purchase of GulfTerra common units from El Paso		(2,876,620)
GulfTerra common units outstanding subject exchange offer		57,762,369
Conversion ratio (1.81 of our common units for each GulfTerra common unit)		1.81
Common units issued to GulfTerra common unitholders in connection with GulfTerra Merger (adjusted for fractional common units)		104,549,823
Average closing price per unit of our common units immediately prior to and after proposed GulfTerra Merger was announced on December 15, 2003	$	23.39
Fair value of our common units issued in conversion of remaining GulfTerra common units	$	2,445,420

In accordance with purchase accounting, the $2.4 billion value of our common units was based on the average closing price of our common units immediately prior to and after the proposed merger was announced on December 15, 2003.

Overall, the fair value of equity interests we issued on September 30, 2004 of the GulfTerra Merger was approximately $2.9 billion. The following table presents the detail for this consideration:

Fair value of common units issued in conversion of remaining GulfTerra common units	$ 2,445,420
Fair value of equity interests issued to acquire the remaining 50% membership interest in GulfTerra GP (voting interest) [(1)]	461,347
Fair value of other equity interests issued for unit awards and Series F2 convertible units	4,005
Total value of equity interests issued upon closing of GulfTerra Merger	$ 2,910,772

(1) This fair value is based on 50% of an implied $922.7 million total value for GulfTerra GP, which assumes that the $370.0 million cash payment made by

Enterprise Products GP to El Paso in September 2004 represented 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 acquired from El Paso. The fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425.0 million we paid El Paso in December 2003 to purchase our initial 50% non-voting membership interest in GulfTerra GP. The contribution of this 50% membership interest to

Enterprise Products Partners is allocated for financial reporting purposes to our limited partners and general partner based on the respective ownership percentages and the related allocation of profits and losses of 98% and 2%, respectively, both of which are consistent with the Partnership Agreement.

As a result of the GulfTerra Merger, we assumed GulfTerra s obligation associated with its 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive our common units based on the 1.81 exchange ratio. In 2004, all of the convertible units were exercised and we issued 1,950,317 common units and received net proceeds of $40.0 million.

Units issued in connection with the Encincal acquisition. In July 2006, we issued 7,115,844 common units as partial consideration for the Encinal acquisition. In August 2006, we filed a registration statement for the resale of these common units by affiliates of Lewis. In accordance with purchase accounting, the $181.1 million fair value of these common units was determined using the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. For purposes of this calculation, the average closing price was $25.45 per unit.

Class B Special Units. In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100.0 million. After receiving the approval of our unitholders, we converted the Class B special units into an equal number of common units in July 2004.

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Treasury Units. In 2000, we and a consolidated trust (the 1999 Trust) were authorized by Enterprise Products GP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2005. Common units repurchased under the program are accounted for in a manner similar to treasury stock under the cost method of accounting. For the purpose of calculating both basic and diluted earnings per unit, treasury units are not considered to be outstanding. We reissued 371,113 units and 30,887 units out of treasury in 2004 and 2003, respectively, in connection with the exercise of unit options by employees of EPCO. We retired 30,000 treasury units in 2003 and cancelled the remaining 427,200 treasury units in 2005.

Distributions to Partners

The percentage interest of Enterprise Products GP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. Enterprise Products GP s quarterly incentive distribution thresholds are as follows:

2% of quarterly cash distributions up to $0.253 per unit;

15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and

25% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $86.7 million, $63.9 million and $32.4 million to Enterprise Products GP during the years ended December 31, 2006, 2005 and 2004, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2005 and the related record and distribution payment dates. The quarterly cash distribution rates per unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Distribution per Unit(1)	Record Date	Payment Date
2005			
1st Quarter	$0.4100	Apr. 29, 2005	May 10, 2005
2nd Quarter	$0.4200	Jul. 29, 2005	Aug. 10, 2005
3rd Quarter	$0.4300	Oct. 31, 2005	Nov. 8, 2005
4th Quarter	$0.4375	Jan. 31, 2006	Feb. 9, 2006
2006			
1st Quarter	$0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter	$0.4525	Jul. 31, 2006	Aug. 10, 2006
3rd Quarter	$0.4600	Oct. 31, 2006	Nov. 8, 2006
4th Quarter	$0.4675		

	Jan. 31, 2007	Feb. 8, 2007

(1) Distributions are paid on common and restricted units, and prior to their conversion to common units, were also paid on Class B special units.

Note 16. 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 technologies 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 an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion 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 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 include 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 and/or suppliers. This method of operation 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, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included 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 mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. 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. Beginning with the fourth quarter of 2006, a small portion of our revenues were earned in Canada. See Note 12 for information regarding our acquisition of a Canadian affiliate of EPCO in October 2006.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset s or investment s principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned 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:

	For the Year Ended December 31,		
	2006	**2005**	**2004**
Revenues [1]	$ 13,990,969	$ 12,256,959	$ 8,321,202
Less: Operating costs and expenses [1]	(13,089,091)	(11,546,225)	(7,904,336)
Add: Equity in income of unconsolidated affiliates [1]	21,565	14,548	52,787
Depreciation, amortization and accretion in operating costs and expenses [2]	440,256	413,441	193,734
Operating lease expenses paid by EPCO[2]	2,109	2,112	7,705
Gain on sale of assets in operating costs and expenses [2]	(3,359)	(4,488)	(15,901)
Total segment gross operating margin	$ 1,362,449	$ 1,136,347	$ 655,191

(1) These amounts are taken from our Statements of Consolidated Operations.

These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	For the Year Ended December 31,		
	2006	**2005**	**2004**
Total segment gross operating margin	$1,362,449	$1,136,347	$ 655,191
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(440,256)	(413,441)	(193,734)
Operating lease expense paid by EPCO	(2,109)	(2,112)	(7,705)

Gain on sale of assets in operating costs and expenses	3,359	4,488	15,901
General and administrative costs	(63,391)	(62,266)	(46,659)
Consolidated operating income	860,052	663,016	422,994
Other expense, net	(229,967)	(225,178)	(153,625)
Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 630,085	$ 437,838	$ 269,369

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Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable 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, 2006	$144,065	$1,401,486	$10,079,534	$1,956,268	$	$	$13,581,353
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
Revenues from related parties:							
Year ended December 31, 2006	1,798	297,409	110,409				409,616
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
Intersegment and intrasegment revenues:							
Year ended December 31, 2006	1,679	113,132	4,131,776	383,754		(4,630,341)	
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)	
Total revenues:							
Year ended December 31, 2006	147,542	1,812,027	14,321,719	2,340,022		(4,630,341)	13,990,969
	112,149	1,577,178	12,358,182	1,933,600		(3,724,150)	12,256,959

Year ended December 31, 2005							
Year ended December 31, 2004	33,061	816,159	8,166,045	1,655,360		(2,349,423)	8,321,202
Equity in income of unconsolidated affiliates:							
Year ended December 31, 2006	11,909	2,872	5,715	1,069			21,565
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
Gross operating margin by individual business segment and in total:							
Year ended December 31, 2006	103,407	333,399	752,548	173,095			1,362,449
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
Segment assets:							
At December 31, 2006	734,659	3,611,974	3,249,486	502,345		1,734,083	9,832,547
At December 31, 2005	632,222	3,622,318	3,075,048	504,841		854,595	8,689,024
Investments in and advances to unconsolidated affiliates (see Note 11):							
At December 31, 2006	310,136	124,591	111,229	18,603			564,559
At December 31, 2005	316,844	4,644	130,376	20,057			471,921
Intangible Assets (see Note 13):							
At December 31, 2006	152,376	386,149	417,950	47,480			1,003,955

At December 31, 2005	174,532	413,843	275,778	49,473		913,626
Goodwill (see Note 13):						
At December 31, 2006	82,135	282,121	152,595	73,690		590,541
At December 31, 2005	82,386	282,997	54,960	73,690		494,033

In general, our historical operating results and/or financial position have been affected by business combinations and other acquisitions. Our most significant business combination to date was the GulfTerra Merger in September 2004 (see Note 12). The value of total consideration we paid or issued to complete the GulfTerra Merger was approximately $4.0 billion. The operating results of entities and assets we acquire are included in our financial results prospectively from their purchase dates.

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Note 17. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Year Ended December 31, 2006	2005	2004
Revenues from consolidated operations			
EPCO and affiliates	$ 98,671	$ 311	$ 2,697
Shell			542,912
Unconsolidated affiliates	304,559	354,461	258,541
Total	$403,230	$354,772	$804,150
Operating costs and expenses			
EPCO and affiliates	$311,537	$293,134	$203,100
Shell			725,420
Unconsolidated affiliates	31,606	23,563	37,587
Total	$343,143	$316,697	$966,107
General and administrative expenses			
EPCO and affiliates	$ 41,265	$ 40,954	$ 29,307

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities:

§ EPCO and its private company subsidiaries;

§ Enterprise Products GP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ Duncan Energy Partners, which is a public company subsidiary of ours;

§ TEPPCO and TEPPCO GP, which are controlled by affiliates of EPCO; and

§ the Employee Partnerships.

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.

EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP, our general partner. At December 31, 2006, EPCO and its affiliates beneficially owned 146,768,946 (or 33.9%) of our outstanding common units, which includes 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2006, EPCO and its affiliates beneficially owned 86.7% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of Enterprise Products GP. The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and EPE Holdings are employees of EPCO.

In connection with its general partner interest in us, Enterprise Products GP received cash distributions of $126.0 million, $76.8 million and $40.4 million from us during the years ended December 31, 2006, 2005 and 2004, respectively. These amounts include incentive distributions of $86.7 million, $63.9 million and $32.4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

We and Enterprise Products GP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its affiliates received $306.5 million, $243.9 million and $189.8 million in cash distributions from us during the years ended December 31, 2006, 2005 and 2004, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO.

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. For the years ended December 31, 2006, 2005 and 2004, we paid this trucking affiliate $20.7 million, $17.6 million and $14.2 million, respectively, for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the years ended December 31, 2006, 2005 and 2004, we paid EPCO $3.0 million, $2.7 million and $1.7 million, respectively, for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sell of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition (see Note 15). For the years ended December 31, 2005 and 2004, our revenues from this former affiliate were $0.3 million and $2.7 million, respectively, and our purchases were $61.0 million and $71.8 million, respectively. For the nine months ended September 30, 2006, our revenues from this former affiliate were $55.8 million and our purchases were $43.4 million.

Relationship with Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.3 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount 5,371,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,371,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under our Operating Partnership s Multi-Year Revolving Credit Facility.

In summary, we contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

§ *Mont Belvieu Caverns, LLC* (Mont Belvieu Caverns), a recently formed subsidiary, which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;

§ *Acadian Gas, LLC* (Acadian Gas), which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns our 49.5% equity interest in Evangeline. See Note 11;

§ *Sabine Propylene Pipeline L.P.* (Sabine Propylene), which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;

§ *Enterprise Lou-Tex Propylene Pipeline L.P.* (Lou-Tex Propylene), which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and

§ *South Texas NGL Pipelines, LLC* (South Texas NGL), a recently formed subsidiary, which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition to the 34% direct ownership interest we retained in certain subsidiaries of Duncan Energy Partners, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners outstanding common units. Our Operating Partnership directs the business operations of Duncan Energy Partners through its ownership and control of the general partner of Duncan Energy Partners.

The formation of Duncan Energy Partners had no effect on our financial statements at December 31, 2006. For financial reporting purposes, the consolidated financial statements of Duncan Energy Partners will be consolidated into those of our own. Consequently, the results of operations of Duncan Energy Partners will be a component of our business segments. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners will reflect our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners.

The public owners of Duncan Energy Partners common units will be presented as a noncontrolling interest in our consolidated financial statements beginning in February 2007. The public owners of Duncan Energy Partners have no direct equity interests in us as a result of this transaction. The borrowings of Duncan Energy Partners will be presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

§ We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;

§ We buy natural gas from and sell natural gas to Acadian Gas in connection with its normal business activities; and

§ We are the sole shipper on the DEP South Texas NGL Pipeline System.

Omnibus Agreement. In connection with the initial public offering of common units by Duncan Energy Partners, our Operating Partnership also entered into an Omnibus Agreement with Duncan Energy Partners and certain of its subsidiaries that will govern our relationship with Duncan Energy Partners on the following matters:

§ indemnification for certain environmental liabilities, tax liabilities and right-of-way defects;

§ reimbursement of certain expenditures for South Texas NGL and Mont Belvieu Caverns;

§ a right of first refusal to the Operating Partnership on the equity interests in the current and future subsidiaries of Duncan Energy Partners and a right of first refusal on the material assets of these entities, other than sales of inventory and other assets in the ordinary course of business; and

§ a preemptive right with respect to equity securities issued by certain of Duncan Energy Partners subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

Indemnification for Environmental and Related Liabilities. Our Operating Partnership also agreed to indemnify Duncan Energy Partners after the closing of its initial public offering against certain environmental and related liabilities arising out of or associated with the operation of the assets before February 5, 2007. These liabilities include both known and unknown environmental and related liabilities. This indemnification obligation will terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage. In addition, Duncan Energy Partners is not entitled to indemnification until the aggregate amounts of its claims exceed $250.0 thousand. Liabilities resulting from a change of law after February 5, 2007 are excluded from the environmental indemnity provided by the Operating Partnership.

In addition, our Operating Partnership will indemnify Duncan Energy Partners for liabilities related to:

§ certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners on February 5, 2007 are located;

§ failure to obtain certain consents and permits necessary for Duncan Energy Partners to conduct its business that arise within three years after February 5, 2007; and

§ certain income tax liabilities related to the operation of the assets contributed to Duncan Energy Partners attributable to periods prior to February 5, 2007.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners in the near term and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions to Duncan Energy Partners.

Reimbursement for Certain Expenditures. Our Operating Partnership has agreed to make additional contributions to Duncan Energy Partners as reimbursement for its 66% share of excess construction costs, if any, above (i) the $28.6 million of estimated capital expenditures to complete planned expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional planned brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. We estimate the costs to complete the planned expansion of the DEP South Texas NGL Pipeline System after the closing of the Duncan Energy Partners initial public offering would be approximately $28.6 million, of which Duncan Energy Partners 66% share would be approximately $18.9 million. Duncan Energy Partners retained cash from the proceeds of its initial public offering in an amount equal to 66% of these estimated planned expansion costs. The Operating Partnership will make a capital contribution to South Texas NGL for its 34% share of such planned expansion costs.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 in connection with the acquisition of TEPPCO GP by a private company subsidiary of EPCO.

We received $42.9 million and a nominal amount from TEPPCO during the years ended December 31, 2006 and 2005, respectively, from the sale of hydrocarbon products. We paid TEPPCO $24.0 million and $17.2 million for NGL pipeline transportation and storage services during the years ended December 31, 2006 and 2005, respectively. We did not sell hydrocarbon products to TEPPCO or utilize its NGL pipeline transportation and storage services during the year ended December 31, 2004.

Purchase of Pioneer plant from TEPPCO. In March 2006, we paid TEPPCO $38.2 million for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to natural gas production from the Jonah and Pinedale fields located in the Greater Green River

Basin in Wyoming. After an in-depth consideration of all relevant factors, this transaction was approved by the Audit and Conflicts Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor. TEPPCO will have no continued involvement in the contracts or in the operations of the Pioneer facility.

Jonah Joint Venture with TEPPCO. In August 2006, we announced a joint venture in which we and TEPPCO will be partners in TEPPCO s Jonah Gas Gathering Company, or Jonah. Jonah owns the Jonah Gas Gathering System (the Jonah Gathering System), located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we signed in February 2006. In connection with the joint venture arrangement, we and TEPPCO will continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.4 Bcf/d. The Phase V expansion is also expected to significantly reduce system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to 2 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $302.0 million. The second portion of the expansion is expected to cost approximately $142.0 million and be completed by the end of 2007.

We manage the Phase V construction project. TEPPCO is entitled to all distributions from the joint venture until specified milestones are achieved, at which point, we will be entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and TEPPCO will share distributions based on a formula that takes into account the respective capital contributions of the parties, including expenditures by TEPPCO prior to the expansion.

Since August 1, 2006, we and TEPPCO equally share in the construction costs of the Phase V expansion. During 2006, TEPPCO reimbursed us $109.4 million, which represents 50% of total Phase V costs incurred through December 31, 2006. We had a receivable of $8.7 million from TEPPCO at December 31, 2006 for Phase V expansion costs.

Upon completion of the expansion project and based on the formula in the joint venture partnership agreement, we expect to own an interest in Jonah of approximately 20%, with TEPPCO owning the remaining 80%. At December 31, 2006, we owned an approximate 14.4% interest in Jonah. We will operate the Jonah Gathering System.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the Audit and Conflicts Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. The ACG Committee of Enterprise Products GP received a fairness opinion in connection with this transaction. In our Form 10-Q for the nine months ended September 30, 2006, we mistakenly reported that the Audit & Conflicts Committee of TEPPCO GP had also received a fairness opinion in connection with this transaction; however, they did not. The transaction was reviewed and recommended for approval by the Audit Committee of TEPPCO GP, with assistance from an independent financial advisor.

We account for our investment in the Jonah joint venture using the equity method. As a result of entering into the Jonah joint venture, we reclassified $52.1 million expended on this project through July 31, 2006 (representing our 50% share at inception of the joint venture) from Other Assets to Investments in and advances to unconsolidated affiliates on our Consolidated Balance Sheets (see Note 11). The remaining $52.1 million we spent through this date is included in the $109.4 million we billed TEPPCO (see above).

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash (see Note 10). The acquired pipelines will be modified for natural gas service. The purchase of this asset was in accordance with the Board-approved management authorization policy.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million that is part of the DEP South Texas NGL Pipeline. In addition, we entered into a lease with TEPPCO for a 11-mile interconnecting pipeline located in the Houston area. The primary term of this lease expires in September 2007, and will continue on a month-to-month basis subject to termination by either party upon 60 days notice. This pipeline is being leased by a subsidiary of Duncan Energy Partners in connection with operations on its DEP South Texas NGL Pipeline until construction of a parallel pipeline is completed. These transactions were in accordance with the Board-approved management authorization policy.

Relationship with Employee Partnerships

EPE Unit I. In connection with the initial public offering of Enterprise GP Holdings, EPCO formed EPE Unit I to serve as an incentive arrangement for certain employees of EPCO through a profits interest in EPE Unit I. EPCO serves as the general partner of EPE Unit I. In connection with the closing of Enterprise GP Holdings initial public offering, EPCO Holdings, Inc., a wholly owned subsidiary of EPCO, borrowed $51.0 million under its credit facility and contributed the proceeds to its wholly-owned subsidiary, Duncan Family Interests, Inc. (Duncan Family Interests).

Subsequently, Duncan Family Interests contributed the $51.0 million to EPE Unit I as a capital contribution and was issued the Class A limited partner interest in EPE Unit I. EPE Unit I used the contributed funds to purchase 1,821,428 units directly from Enterprise GP Holdings at the initial public offering price of $28.00 per unit. Certain EPCO employees, including all of Enterprise Products GP s then current executive officers other than the Chairman, were issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of EPE Unit I.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of EPE Unit I, EPE Unit I will terminate at the earlier of five years following the closing of Enterprise GP Holdings initial public offering or a change in control of Enterprise GP Holdings or its general partner. EPE Unit I has the following material terms regarding its quarterly cash distribution to partners:

§ Distributions of Cash Flow - Each quarter, 100% of the cash distributions received by EPE Unit I from Enterprise GP Holdings will be distributed to the Class A limited partner until Duncan Family Interests has received an amount equal to the Class A preferred return (as defined below), and any remaining distributions received by EPE Unit I will be distributed to the Class B limited partners. The Class A preferred return equals 1.5625% per quarter, or 6.25% per annum, of the Class A limited partner s capital base. The Class A limited partner s capital base equals $51 million plus any unpaid Class A preferred return from prior periods, less any distributions made by EPE Unit I of proceeds from the sale of Enterprise GP Holdings units owned by EPE Unit I (as described below).

- § Liquidating Distributions - Upon liquidation of EPE Unit I, units having a fair market value equal to the Class A limited partner 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 EPE Unit I sells any of the 1,821,428 Enterprise GP Holdings units that it owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in EPE Unit I 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 Enterprise GP Holdings 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 EPE Unit I will also lapse upon certain change of control events.

Since Enterprise GP Holdings has an indirect interest in us through its ownership of our general partner, EPE Unit I, including its Class B limited partners, may derive some benefit from our results of operations. Accordingly, a portion of the fair value of these equity awards is allocated to us under the EPCO administrative services agreement as a non-cash expense. We, Enterprise Products GP, Duncan Energy Partners, DEP Holdings and Enterprise GP Holdings will not reimburse EPCO, EPE Unit I or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to EPE Unit I, including the contribution of $51 million to EPE Unit I by Duncan Family Interests or the purchase of Enterprise GP Holdings units by EPE Unit I.

For the period that EPE Unit I was in existence during 2005, EPCO accounted for this equity-based awards using the provisions of APB 25. Under APB 25, the intrinsic value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights (i.e. variable accounting). Upon our adoption of SFAS 123(R), we began recognizing compensation expense based upon the estimated grant date fair value of the Class B partnership equity awards. 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. For the years ended December 31, 2006 and 2005, we recorded $2.1 million and $2.0 million, respectively, of non-cash compensation expense for these awards associated with employees who work on our behalf.

EPE Unit II. In December 2006, EPE Unit II was formed to serve as an incentive arrangement for an executive officer of our general partner. This officer, who is not a participant in EPE Unit I, was granted a profits interest in EPE Unit II. EPCO serves as the general partner of EPE Unit II.

Duncan Family Interests contributed $1.5 million to EPE Unit II as a capital contribution and was issued the Class A limited partner interest in EPE Unit II. EPE Unit II used these funds to purchase 40,725 units of Enterprise GP Holdings on the open market at an average price of $36.91 per unit in December 2006. The officer was issued a Class B limited partner interest in EPE Unit II without any capital contribution. The significant terms of EPE Unit II (e.g. termination provisions, quarterly distributions of cash flow, liquidating distributions, forfeitures, and treatment of sale proceeds) are similar to those for EPE Unit I except that the Class A capital base for Duncan Family Interest is $1.5 million.

As with EPE Unit I, EPCO s non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of the officer s services. In accordance with SFAS 123(R), we recognize compensation expense associated with EPE Unit II based on the estimated grant date fair value of the Class B partnership equity award. Since EPE Unit II was formed in December 2006, we recorded a nominal amount of expense associated with this award during the year ended December 31, 2006.

See Note 5 for additional information regarding our accounting for equity awards.

EPCO 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 (the ASA). We and our general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner, and TEPPCO and its general partner, among other affiliates, are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services, and management 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 will allow us to participate as named insureds in its overall insurance program, with the associated premiums and other costs being allocated 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, with the offset to partners equity accounted for as a general contribution to our partnership. 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 2006, 2005 and 2004 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 2006, 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).

The ASA also addresses potential conflicts that may arise among us and our general partner, Duncan Energy Partners and its general partner, DEP Holdings, LLC (DEP Holdings) Enterprise GP Holdings and its general partner, and the EPCO Group, which includes EPCO and its affiliates (but does not include the aforementioned entities and their controlled affiliates). The administrative services agreement provides, among other things, that:

§ If a business opportunity to acquire *equity securities (as defined)* is presented to the EPCO Group, us and our general partner, Duncan Energy Partners, its general partner, and its operating partnership, or Enterprise GP Holdings and its general partner, then Enterprise GP Holdings will have the first right to pursue such opportunity. The term equity securities is 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

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(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.

Enterprise GP Holdings will be presumed to desire to acquire the equity securities until such time as its general partner advises the EPCO Group, Enterprise Products GP and DEP Holdings that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or 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 ACG 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 ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, Enterprise Products GP and DEP Holdings, we will have the second right to pursue such acquisition either for us or, if desired by us in our sole discretion, for the benefit of Duncan Energy Partners. In the event that we affirmatively direct the opportunity to Duncan Energy Partners, Duncan Energy Partners may pursue such acquisition. We will be presumed to desire to acquire the equity securities until such time as Enterprise Products GP advises the EPCO Group and DEP Holdings that we have abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, we will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing Enterprise Products GP s chief executive officer and ACG Committee. In the event we abandon the acquisition opportunity for the equity securities and so notify the EPCO Group and DEP Holdings, the EPCO Group may pursue the acquisition or offer the opportunity to EPCO Holdings or TEPPCO, TEPPCO GP and their controlled affiliates, in either case, 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 (i.e. not involving equity securities) is presented to the EPCO Group, Enterprise GP Holdings, EPE Holdings, Duncan Energy Partners, DEP Holdings, our general partner or us, we will have the first right to pursue such opportunity either for us or, if desired by us in our sole discretion, for the benefit of Duncan Energy Partners. We will be presumed to desire to pursue the business opportunity until such time as Enterprise Products GP advises the EPCO Group, EPE Holdings and DEP Holdings that we have abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100 million, any 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 ACG 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 ACG Committee. In the event that we affirmatively direct the business opportunity to Duncan Energy Partners, Duncan Energy Partners may pursue such business opportunity. In the event that we abandon the business opportunity for us and for Duncan Energy Partners and so notify the EPCO Group, EPE Holdings and DEP Holdings, Enterprise GP Holdings will have the second right to pursue such business opportunity, and will be presumed to desire to do so, until such time as EPE Holdings shall have determined to abandon the pursuit of such opportunity in accordance with the procedures described above, and shall have advised the EPCO Group that Enterprise GP Holdings has abandoned the pursuit of such acquisition.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, the EPCO Group may either pursue the business opportunity or offer the business opportunity to EPCO Holdings or TEPPCO, TEPPCO GP and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise GP Holdings, EPE Holdings, DEP Holdings, Duncan Energy Partners or its operating partnership, our general partner or us have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates. Likewise, TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise GP Holdings, EPE Holdings, DEP Holdings, Duncan Energy Partners or its operating partnership, our general partner or us.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 16 for a discussion of this alignment of commercial interests. Since we and our 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 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 $277.7 million, $318.8 million and $233.9 million for the years ended December 31, 2006, 2005 and 2004. In addition, we furnished $1.1 million in letters of credit on behalf of Evangeline at December 31, 2006.

§ 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 $34.9 million, $26.0 million and $23.2 million for the years ended December 31, 2006, 2005 and 2004. Additionally, revenues from Promix were $21.8 million, $25.8 million and $18.6 million for the years ended December 31, 2006, 2005 and 2004.

§ We perform management services for certain of our unconsolidated affiliates. These fees were $8.9 million, $8.3 million and $2.1 million for the years ended December 31, 2006, 2005 and 2004.

Review and Approval of Transactions with Related Parties

Our partnership agreement and ACG Committee charter set forth policies and procedures for the review and approval of certain transactions with persons affiliated with or related to us. As further described below, our partnership agreement and ACG Committee charter set forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the general partner or the ACG Committee. Under our partnership agreement, unless otherwise expressly provided therein or in the partnership agreements of the Operating Partnership, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by the general partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement, the partnership agreement of the Operating Partnership or any agreement contemplated by such agreements, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; *provided* that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our ACG Committee (Special Approval), as long as the material facts within the actual knowledge of the officers and directors of the General Partner and EPCO regarding the proposed transaction were disclosed to the committee at the time it gave its approval, or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its determination of what is fair and reasonable to the Partnership and in connection with its resolution of any conflict of interest to consider:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ any customary or accepted industry practices and any customary or historical dealings with a particular person;

§ any applicable generally accepted accounting practices or principles; and

§ such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

Our Board of Directors or our general partner may, in their discretion, request that our ACG Committee review and approve related party transactions. The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee s Special Approval is conclusively deemed fair and reasonable to us under the partnership agreement. The processes followed by our management in approving or obtaining approval of related party transactions are in accordance with our written management authorization policy, which has been approved by the Board.

Under our Board-approved management authorization policy, the officers of our general partner have authorization limits for purchases and sales of assets, capital expenditures, commercial and financial transactions and legal agreements that ultimately limit the ability of executives of our general partner to enter into transactions involving capital expenditures in excess of $100 million without Board approval. This policy covers all transactions, including transactions with related parties. For example, under this policy, the chairman of our general partner may approve capital expenditures or the sale or other disposition of our assets up to a $100 million limit. Furthermore, any two of the chief executive officer and senior executives who are directors of our general partner may approve capital expenditures or the sale or other disposition of our assets up to a $100 million limit and and individually may approve capital expenditures or the sale or other disposition of our assets up to $50 million. These senior executives have also been granted full approval authority for commercial, financial and service contracts.

In submitting a matter to the ACG Committee, the Board or the general partner may charge the committee with reviewing the transaction and providing the Board a recommendation, or it may delegate to the committee the power to approve the matter. When so engaged, the ACG Committee Charter currently provides that, unless the ACG Committee otherwise determines, the ACG Committee shall perform the following functions:

§ Review a summary of the proposed transaction(s) that outlines (i) its terms and conditions (explicit and implicit), (ii) a brief history of the transaction, and (iii) the impact that the transaction will have on our unitholders and personnel, including earnings per unit and distributable cash flow.

§ Review due diligence findings by management and make additional due diligence requests, if necessary.

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§ Engage third-party independent advisors, where necessary, to provide committee members with comparable market values, legal advice and similar services directly related to the proposed transaction.

§ Conduct interviews regarding the proposed transaction with the most knowledgeable company officials to ensure that the committee members have all relevant facts before rendering their judgment.

In the normal course of business, our management routinely reviews all other related party transactions, including proposed asset purchases and business combinations and purchases and sales of product. As a matter of course, management reviews the terms and conditions of the proposed transactions, performs appropriate levels of due diligence and assesses the impact of the transaction on our partnership.

The ACG Committee does not separately review transactions covered by our administrative services agreement with EPCO, which agreement has previously been approved by the ACG Committee and/or the Board. The administrative services agreement governs numerous day-to-day transactions between us and our subsidiaries and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs for those services. For a description of the administrative services agreement, please read "*Relationship with EPCO and affiliates Administrative Services Agreement* within this Item 13.

Since the beginning of the last fiscal year of our partnership, the ACG Committee reviewed and approved the purchase of the Pioneer plant from TEPPCO and Jonah Joint Venture with TEPPCO referenced under this Item 13. All other transactions with related parties referenced under this Item 13 were either governed by the administrative services agreement or effected under our written management authorization policy.

Relationship with Shell

Historically, Shell was considered a related party because it owned more than 10% of our limited partner interests 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 us to third parties, Shell owned less than 10% of our 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 us and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party in January 2005. At December 31, 2006, Shell owned 26,976,249, or 6.2%, of our common units, all of which have been registered for resale in the open market by us. At February 1, 2007, Shell owned 19,635,749 or 4.5% of our common units.

For the year ended December 31, 2004, our revenues from Shell primarily reflected the sale of NGL and certain petrochemical products and the fees we charged for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflected the payment of energy-related expenses related to the Shell Processing Agreement and the purchase of NGL products. 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.

Note 18. Provision for Income Taxes

Our provision for income taxes relates primarily to federal and state income taxes of Seminole and Dixie, our two largest corporations subject to such income taxes. In addition, with the enactment of the Texas Margin Tax in 2006, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	For the Year Ended December 31,		
	2006	2005	2004
Current:			
Federal	$ 7,694	$1,105	$
State	1,148	301	157
Total current	8,842	1,406	157
Deferred:			
Federal	6,109	5,968	1,620
State	6,372	988	1,984
Total deferred	12,481	6,956	3,604
Total provision for income taxes	$21,323	$8,362	$3,761

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 is as follows:

	For the Year Ended December 31,		
	2006	2005	2004
Taxes computed by applying the federal statutory rate	$13,347	$7,656	$2,308
State income taxes (net of federal benefit)	7,723	838	1,392
Taxes charged to cumulative effect of changes in accounting principle	(3)	65	
Other permanent differences	256	(197)	61
Provision for income taxes	$21,323	$8,362	$3,761
Effective income tax rate	56%	38%	57%

Significant components of deferred tax liabilities and deferred tax assets as of December 31, 2006 and 2005 are as follows:

	At December 31,	
	2006	2005
Deferred Tax Assets:		
Property, plant and equipment Dixie	$	$ 855
Net operating loss carryforwards	19,175	17,121
Credit carryover	26	

Charitable contribution carryover	12	
Employee benefit plans	1,990	2,403
Deferred revenue	328	448
Equity investment in partnerships	223	
Asset retirement obligation	43	
Accruals	709	116
Total Deferred Tax Assets	22,506	20,943
Valuation allowance	(2,994)	(2,870)
Net Deferred Tax Assets	19,512	18,073
Deferred Tax Liabilities:		
Property, plant and equipment	30,604	13,907
Other	78	6
Total Deferred Tax Liabilities	30,682	13,913
Total Net Deferred Tax Assets (Liabilities)	$(11,170)	$ 4,160
Current portion of total net deferred tax assets	$ 698	$ 554
Long-term portion of total net deferred tax assets (liabilities)	$(11,868)	$ 3,606

We had net operating loss carryforwards of $19.2 million and $17.1 million at December 31, 2006 and 2005, respectively. These losses expire in various years between 2007 and 2026 and are subject to limitations on their utilization. We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. The valuation allowance was $3.0 million and $2.9 million at December 31, 2006 and 2005, respectively, and primarily relates to our net operating loss carryforwards.

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period of the law s enactment. We recorded a net deferred tax liability of $6.6 million due to the enactment of the Texas margin tax. The offsetting net charge of $6.6 million is shown on our Statement of Consolidated Operations for the year ended December 31, 2006 as a component of provision for income taxes.

Texas margin tax is effective for returns originally due on or after January 1, 2008. For calendar year end companies, the margin tax would be applied to 2007 activity.

Note 19. 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 units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the incremental option units).

The distribution-bearing Class B special units were included in the calculation of basic earnings per unit prior to their conversion to common units in July 2004.

Treasury units were not considered to be outstanding units; therefore, they were excluded from the computation of both basic and diluted earnings per unit.

In a period of net operating losses, restricted units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

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The amount of net income or loss allocated to limited partner interests is net of our general partner s share of such earnings. The following table presents the allocation of net income to Enterprise Products GP for the periods indicated:

	For The Year Ended December 31, 2006	2005	2004
Net income	$601,155	$419,508	$268,261
Less incentive earnings allocations to Enterprise Products GP	(86,710)	(63,884)	(32,391)
Net income available after incentive earnings allocation	514,445	355,624	235,870
Multiplied by Enterprise Products GP ownership interest	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise Products GP	$ 10,289	$ 7,112	$ 4,717
Incentive earnings allocation to Enterprise Products GP	$ 86,710	$ 63,884	$ 32,391
Standard earnings allocation to Enterprise Products GP	10,289	7,112	4,717
Enterprise Products GP interest in net income	$ 96,999	$ 70,996	$ 37,108

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For The Year Ended December 31, 2006	2005	2004
Income before changes in accounting principles and Enterprise Products GP interest	$599,683	$423,716	$257,480
Cumulative effect of changes in accounting principles	1,472	(4,208)	10,781
Net income	601,155	419,508	268,261
Less Enterprise Products GP interest in net income	(96,999)	(70,996)	(37,108)
Net income available to limited partners	$504,156	$348,512	$231,153
BASIC EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise Products GP interest	$599,683	$423,716	$257,480
Cumulative effect of changes in accounting principles	1,472	(4,208)	10,781
Enterprise Products GP interest in net income	(96,999)	(70,996)	(37,108)
Limited partners interest in net income	$504,156	$348,512	$231,153
Denominator			
Common units	413,472	381,857	262,838
Restricted units	970	606	141
Class B special units			2,532
Total	414,442	382,463	265,511
Basic earnings per unit			
Income per unit before changes in accounting principles and Enterprise Products GP interest	$ 1.45	$ 1.11	$ 0.97
Cumulative effect of changes in accounting principles		(0.01)	0.04
Less Enterprise Products GP interest in net income	(0.23)	(0.19)	(0.14)
Limited partners interest in net income	$ 1.22	$ 0.91	$ 0.87
DILUTED EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise Products GP interest	$599,683	$423,716	$257,480
Cumulative effect of changes in accounting principles	1,472	(4,208)	10,781
Less Enterprise Products GP interest in net income	(96,999)	(70,996)	(37,108)
Limited partners interest in net income	$504,156	$348,512	$231,153
Denominator			
Common units	413,472	381,857	262,838

Class B special units			2,532
Time-vested restricted units	970	606	141
Performance-based restricted units	20	45	14
Series F2 convertible units			22
Incremental option units	297	455	498
Total	414,759	382,963	266,045
Diluted earnings per unit			
Income per unit before changes in accounting principles and Enterprise Products GP interest	$ 1.45	$ 1.11	$ 0.97
Cumulative effect of changes in accounting principles		(0.01)	0.04
Enterprise Products GP interest in net income	(0.23)	(0.19)	(0.14)
Limited partners interest in net income	$ 1.22	$ 0.91	$ 0.87

Note 20. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business activities, 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 activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, cash flows or results of operations.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether (MTBE). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

We acquired additional ownership interests in our Mont Belvieu, Texas octane-additive production facility from affiliates of Devon Energy Corporation (Devon), which sold us its 33.3% interest in 2003, and Sunoco, Inc. (Sun), which sold us its 33.3% interest in 2004. As a result of these acquisitions, we own 100% of the octane-additive production facility. Devon and Sun have indemnified us for any liabilities (including potential liabilities as described in the preceding paragraph) that are in respect of periods prior to the date we purchased such interests and linked to the period of time they held such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO, and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. The complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates, including the parent company of our general partner; (iii) EPCO, Inc.; and (iv) Dan L. Duncan.

The complaint alleges, among other things, that the defendants have caused TEPPCO to enter into certain transactions with us or our affiliates that are unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include the joint venture to further expand the Jonah Gathering System entered into by TEPPCO and one of our affiliates in August 2006 and the sale by TEPPCO to one of our affiliates of the Pioneer gas processing plant in March 2006. The complaint seeks (i) rescission of these transactions or an award of rescissory damages with respect thereto; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 17 for additional information regarding our relationship with TEPPCO.

On February 13, 2007, our Operating Partnership received notice from the U.S. Department of Justice (DOJ) that it was the subject of a criminal investigation related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (Magellan). Our Operating Partnership is the operator of this pipeline. On February 14, 2007, our Operating Partnership received a letter from the Environment and Natural Resources Division (ENRD) of the DOJ regarding this incident and a previous release of ammonia on September 27, 2004 from the same pipeline. The ENRD has indicated that it may pursue civil damages against our Operating Partnership and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against our Operating Partnership and Magellan is up to $17.4 million in the aggregate. Our Operating Partnership is cooperating with the DOJ and is hopeful that an expeditious resolution acceptable to all parties will be reached in the near future. Our Operating Partnership is seeking defense and indemnity under the pipeline operating agreement between it and Magellan. At this time, we do not believe that a final resolution of either the criminal investigation by the DOJ or the civil claims by the ENRD will have a material impact on our consolidated results of operations.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. We and Magellan are in the process of estimating the repair and remediation costs associated with this release. Environmental remediation efforts continue in and around the site of the release under the supervision and management of affiliates of Magellan. Our operating agreement with Magellan provides the Operating Partnership with an indemnity clause for claims arising from such releases. At this time, we do not believe that this incident will have a material impact on our consolidated results of operations.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2006. A description of each type of contractual obligation follows.

		Payment or Settlement due by Period					
Contractual Obligations	**Total**	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**
Scheduled maturities of long-term debt	$5,329,068	$	$	$500,000	$569,068	$1,360,000	$2,900,000
Operating lease obligations	$ 274,700	$ 19,190	$ 19,877	$ 16,374	$ 15,688	$ 16,263	$ 187,308
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 920,736	$ 153,316	$153,736	$153,316	$153,316	$ 153,316	$ 153,736
NGLs	$2,902,805	$ 959,127	$223,570	$213,315	$213,315	$ 213,315	$1,080,163
Petrochemicals	$2,656,633	$1,110,957	$448,334	$245,028	$220,037	$ 119,397	$ 512,880
Other	$ 79,418	$ 35,183	$ 27,653	$ 13,681	$ 765	$ 659	$ 1,477
Underlying major volume commitments:							
Natural gas (in BBtus)	109,600	18,250	18,300	18,250	18,250	18,250	18,300
NGLs (in MBbls)	68,331	21,957	5,322	5,086	5,086	5,086	25,794
Petrochemicals (in MBbls)	45,535	19,250	7,460	4,289	3,670	2,024	8,842
Service payment commitments	$ 15,725	$ 10,413	$ 3,759	$ 900	$ 93	$ 93	$ 467
Capital expenditure commitments	$ 239,000	$ 239,000	$	$	$	$	$

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements such as the indentures governing our Operating Partnership s senior notes and the credit agreement governing our Operating Partnership s Multi-Year Revolving Credit Facility. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 14 for additional information regarding our consolidated debt obligations.

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.

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 at fixed rates, as specified in the individual contract, and may be subject to escalation provisions for inflation or other market-determined factors. With regards to our leases of underground storage caverns, we may 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. We are generally 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 the years ended December 31, 2006, 2005 or 2004; however, we did incur $9.3 million of repair costs associated with our lease of an underground natural gas storage facility in 2006.

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, 2006, 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 2007 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 the year ended December 31, 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 costs and expenses was $39.3 million, $34.9 million and $19.5 million during the years ended December 31, 2006, 2005 and 2004, 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, certain 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, 2006 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2006, we do not have any product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

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

§ We have short-term payment obligations relating to our capital projects and those of our unconsolidated affiliates. These commitments represent unconditional payment obligations to vendors for services rendered or products purchased. The preceding table presents our share of such commitments for the periods indicated.

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 17). This includes costs associated with unit option awards granted to these employees to purchase our common units. At December 31, 2006, there were 2,416,000 unit options outstanding for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of unit option awards outstanding at December 31, 2006 was $23.32 per common unit. At December 31, 2006, 591,000 of these unit options were exercisable. An additional 785,000 450,000 and 590,000 of these unit options will be exercisable in 2008, 2009 and 2010, 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 ours entered into the Independence Hub Agreement (the Agreement) with six oil and natural gas producers. The Agreement, as amended, obligates our subsidiary to construct the Independence Hub offshore platform and to process 1 Bcf/d of natural gas and condensate for the producers.

We have guaranteed to the producers the construction-related performance of our subsidiary up to an amount of $340.8 million. This figure represents the maximum amount we would pay to the producers in the remote circumstance where they must finish construction of the platform because our subsidiary failed to do so. This guarantee will remain in place until the earlier of (i) the date all guaranteed obligations terminate or expire, or have been paid or otherwise performed or discharged in full, (ii) upon mutual written consent of us, the producers and our joint venture partner in the platform project or (iii) mechanical completion of the platform. We expect that mechanical completion of the Independence Hub platform will occur in March 2007; therefore, we anticipate that our performance guaranty will exist until at least this forecasted 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 we 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, 2006.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2006, our contingent claims against such parties were approximately $2 million and claims against us were approximately $34 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Other Commitments

We transport and store natural gas, NGLs and certain petrochemicals 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 against any physical loss of such volumes due to catastrophic events. At December 31, 2006, NGL and petrochemical volumes aggregating 8.5 million barrels were due to be redelivered to their owners along with 12,063 BBtus of natural gas.

Note 21. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, certain petrochemicals and crude oil. As such, our results of operations, cash flows and financial condition may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these 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 hydrocarbon products transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining for reasons such as depressed commodity prices or a decrease in exploration and development activities, 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 using NGLs, (iii) increased competition from petroleum-based products due to pricing differences, (iv) adverse weather conditions, (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could 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.

Our revenues are derived from a wide customer base. During 2006 and 2005, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.1% and 6.8%, respectively, of our consolidated revenues. During 2004, our largest customer was Shell Oil Company and its affiliates (Shell), which accounted for 6.5% of our consolidated revenues.

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. We generally do not require collateral for our financial instrument transactions.

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. EPCO attempts to place all insurance coverage with carriers having ratings of A or higher. However, two carriers associated with the EPCO insurance program were downgraded to BBB+ by Standard & Poor s during 2006. At present, there is no indication that these carriers would be unable to fulfill any insuring obligation. Furthermore, we currently do not have any claims which might be affected by these carriers. EPCO continues to monitor these situations.

We believe EPCO maintains adequate insurance coverage on our behalf; however, insurance will not cover every type of interruption that might occur. As a result of severe hurricanes such as Katrina and Rita that occurred in 2005, market conditions for obtaining property damage insurance coverage have been difficult. Under EPCO s renewed insurance programs, coverage is more restrictive, including increased physical damage and business interruption deductibles. For example, our deductible for onshore physical damage increased from $2.5 million to $5.0 million per event and our deductible period for onshore business interruption claims increased from 30 days to 60 days. Additional restrictions will be applied in connection with damage caused by named windstorms.

In addition to changes in coverage, the cost of property damage insurance increased substantially from prior periods. At present, our annualized cost of insurance premiums for all lines of coverage is approximately $49.2 million, which represents a $28.1 million, or 133%, increase from our 2005 annualized insurance cost.

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 to reimburse us for repair costs or lost income. 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 common units.

The following is a discussion of the general status of our insurance claims related to recent significant storm events. 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.

Hurricane Ivan insurance claims. Our final purchase price allocation related to the merger of GulfTerra with a wholly owned subsidiary of Enterprise Products Partners in September 2004 (the GulfTerra Merger) included a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain pre-merger GulfTerra assets caused by Hurricane Ivan. During 2006, 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 in 2007. 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 2006, we received $17.4 million of nonrefundable cash proceeds from such claims. We are continuing our efforts to collect residual balances and expect to complete the process during 2007. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as a gain in our Statements of Consolidated Operations 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. The majority of repairs to our facilities are completed; however, certain minor repairs are ongoing to two offshore pipelines and an onshore gas processing facility. To the extent that insurance proceeds from property damage claims are not probable of collection or do not cover our estimated expenditures (in excess of $5.0 million of insurance deductibles we expensed during 2005), such amounts are charged to earnings when realized. With respect to these storms, we have $78.2 million of estimated property damage claims outstanding at December 31, 2006, that we believe are probable of collection during the period 2007 through 2009. For the year ended December 31, 2006, we received $10.5 million of physical damage proceeds related to such storms.

In addition, we received $46.5 million of nonrefundable cash proceeds from business interruption claims during the year ended December 31, 2006. We are aggressively pursuing collection of our remaining property damage and business interruption claims related to Hurricanes Katrina and Rita.

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The following table summarizes proceeds we received during 2006 from business interruption and property damage insurance claims with respect to certain named storms:

Business interruption proceeds:	
Hurricane Ivan	$ 17,382
Hurricane Katrina	24,500
Hurricane Rita	22,000
Total proceeds	$ 63,882
Property damage proceeds:	
Hurricane Ivan	$ 24,104
Hurricane Katrina	7,500
Hurricane Rita	3,000
Total proceeds	$ 34,604
Total proceeds received during 2006	$ 98,486

During 2005, we received $4.8 million of nonrefundable cash proceeds from business interruption claims.

Note 22. 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 the Year Ended December 31,		
	2006	2005	2004
Decrease (increase) in:			