UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004

OR

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

Commission File Number 1-10403

TEPPCO Partners, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	**76-0291058**
(State of Incorporation or Organization)	(I.R.S. Employer Identification Number)

2929 Allen Parkway
P.O. Box 2521
Houston, Texas 77252-2521
(Address of principal executive offices, including zip code)

(713) 759-3636
(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
Limited Partner Units representing Limited Partner Interests	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No 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 an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No o

At June 30, 2004, the aggregate market value of the registrant's Limited Partner Units held by non-affiliates was $2,394,335,251, which was computed using the average of the high and low sales prices of the Limited Partner Units on June 30, 2004.

Limited Partner Units outstanding as of February 25, 2005: **62,998,554**.

Documents Incorporated by Reference: **None**

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PART I

FORWARD-LOOKING STATEMENTS

The matters discussed in this Report include "forward-looking statements" within the meaning of various provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strengths, goals, expansion and growth of our business and operations, plans, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by us, competitive actions by other pipeline companies, changes in laws or regulations and other factors, many of which are beyond our control. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to or effect on us or our business or operations.

Items 1 and 2. *Business and Properties*

General

TEPPCO Partners, L.P. (the "Partnership"), a Delaware limited partnership, is a master limited partnership formed in March 1990. We operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L.P. ("TCTM") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"). Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships." Texas Eastern Products Pipeline Company, LLC (the "Company" or "General Partner"), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. The General Partner is an indirect wholly owned subsidiary of Duke Energy Field Services, LLC ("DEFS"), a joint venture between Duke Energy Corporation ("Duke Energy") and ConocoPhillips. Duke Energy holds an interest of approximately 70% in DEFS, and ConocoPhillips holds the remaining interest of approximately 30%. The Company, as general partner, performs all management and operating functions required for us, except for the management and operations of certain of the TEPPCO Midstream assets that are managed by DEFS on our behalf. We reimburse the General Partner for all reasonable direct and indirect expenses incurred in managing us. TEPPCO GP, Inc. ("TEPPCO GP"), our subsidiary, is the general partner of our Operating Partnerships. We hold a 99.999% limited partner interest in the Operating Partnerships and TEPPCO GP holds a 0.001% general partner interest.

As used in this Report, "we," "us," "our," the "Partnership" and "TEPPCO" means TEPPCO Partners, L.P. and, where the context requires, includes our subsidiaries.

We operate and report in three business segments: transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies.

Our interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC"). We refer to refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas in this Report, collectively, as "petroleum products" or "products."

At December 31, 2004 and 2003, we had outstanding 62,998,554 Limited Partner Units. At December 31, 2002, we had outstanding 3,916,547 Class B Limited Partner Units ("Class B Units"), which were issued to Duke Energy Transport and Trading Company, LLC ("DETTCO") in connection with an acquisition of assets initially acquired in the Upstream Segment in 1998. On April 2, 2003, we repurchased and retired all of the 3,916,547 previously outstanding Class B Units with proceeds from the issuance of additional Limited Partner Units (see Note 11. Partners' Capital and Distributions). Collectively, the Limited Partner Units and Class B Units are referred to as "Units."

Our strategy is to expand and improve service in our current markets, maintain the integrity of our pipeline systems and pursue growth initiatives that are balanced between internal projects and acquisitions. We intend to leverage the advantages inherent in our pipeline systems to maintain our status as a preferred provider in our market areas. We also intend to grow by acquiring assets, from both third parties and affiliates, which complement existing businesses or by establishing new core businesses. We routinely evaluate opportunities to acquire assets and businesses that will complement existing operations with a view to increasing earnings and cash available for distribution to our unitholders. We may fund additional acquisitions with cash flow from operations, borrowings under existing credit facilities, the issuance of debt in the capital markets, the sale of additional Units, or any combination thereof.

Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals

Operations

We conduct business in our Downstream Segment through the following:

- TE Products,
- a subsidiary which owns the northern portion of the Dean Pipeline ("Dean North"),
- our 50% owned equity investment in Centennial Pipeline LLC ("Centennial"), and
- our 50% owned equity investment in Mont Belvieu Storage Partners, L.P. ("MB Storage").

Our Downstream Segment owns, operates or has investments in properties located in 14 states. The operations of the Downstream Segment consist of interstate transportation, storage and terminaling of petroleum products; short-haul shuttle transportation of LPGs at the Mont Belvieu, Texas, complex through MB Storage; intrastate transportation of petrochemicals and other ancillary services.

As an interstate common carrier, our TE Products pipeline offers interstate transportation services, pursuant to tariffs filed with the FERC, to any shipper of refined petroleum products and LPGs who requests these services, provided that the products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. In addition to the revenues received by our pipeline system from our interstate tariffs, we also provide storage and other related services at key points along our pipeline systems. Substantially all of the petroleum products transported and stored in our pipeline systems are owned by our customers. Petroleum products are received at terminals located principally on the southern end of the pipeline system, stored, scheduled into the pipeline in accordance with customer nominations and shipped to delivery terminals for ultimate delivery to the final distributor (including gas stations and retail propane distribution centers) or to other pipelines. Pipelines are generally the lowest cost method for intermediate and long-haul overland transportation of petroleum products. The TE Products pipeline system is the only pipeline that transports LPGs from the upper Texas Gulf Coast to the Northeast.

Our Downstream Segment depends in large part on the level of demand for refined petroleum products and LPGs in the geographic locations that we serve and the ability and willingness of customers having access to the pipeline system to supply this demand. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, governmental regulation or technological advances in fuel economy and energy-generation devices, all of which could reduce the demand for refined petroleum products and LPGs in the areas we serve.

The following table lists the material properties and investments of and ownership percentages in the Downstream Segment assets as of December 31, 2004:

	Our Ownership
Refined products and LPGs pipelines	100%
Mont Belvieu, Texas, to Port Arthur, Texas, petrochemical pipelines	100%
Northern portion of Dean Pipeline (1)	100%
Centennial Pipeline LLC (2)	50%
Mont Belvieu Storage Partners, L.P. (3)	50%

(1) Effective January 1, 2003, the northern portion of the Dean Pipeline was converted to transport refinery grade propylene ("RGP") from Mont Belvieu, Texas, to Point Comfort, Texas.

(2) Accounted for as an equity investment. Effective February 10, 2003, TE Products acquired an additional 16.7% interest in Centennial, bringing its ownership percentage to 50%.

(3) Accounted for as an equity investment. Effective January 1, 2003, TE Products contributed substantially all of its Mont Belvieu LPG assets to MB Storage, a partnership formed with Louis Dreyfus Energy Services L.P. ("Louis Dreyfus").

Centennial Pipeline Equity Investment

In August 2000, TE Products entered into agreements with Panhandle Eastern Pipeline Company ("PEPL"), a former subsidiary of CMS Energy Corporation, and Marathon Ashland Petroleum LLC ("Marathon") to form Centennial. Each participant originally owned a one-third interest in Centennial.

Centennial, which commenced operations in April 2002, owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Centennial constructed a 74-mile, 24-inch diameter pipeline connecting TE Products' facility in Beaumont, Texas, with an existing 720-mile, 26-inch diameter pipeline extending from Longville, Louisiana, to Bourbon, Illinois. The Centennial pipeline intersects TE Products' existing mainline pipeline near Creal Springs, Illinois, where Centennial constructed a two million barrel refined petroleum products storage terminal. Marathon operates the mainline Centennial pipeline, and TE Products operates the Beaumont origination point and the Creal Springs terminal.

TE Products' interest in Centennial is not subject to any encumbrances from mortgages or other secured debt. Centennial has unsecured debt, one third of which, up to $50.0 million in principal, was originally guaranteed by each owner, including TE Products. On February 10, 2003, TE Products and Marathon each acquired an additional 16.7% interest in Centennial from PEPL for $20.0 million each, increasing their percentage ownerships in Centennial to 50% each. TE Products and Marathon have each guaranteed one-half of Centennial's debt, up to a maximum of $75.0 million each. Through December 31, 2004, including the amount paid for the acquisition of the additional ownership interest in February 2003, TE Products has invested $104.8 million in Centennial. TE Products has not received any distributions from Centennial since its formation.

Mont Belvieu Storage Equity Investment

On January 1, 2003, TE Products and Louis Dreyfus formed MB Storage. TE Products and Louis Dreyfus each own a 50% ownership interest in MB Storage. The purpose of MB Storage is to expand services to the upper Texas Gulf Coast energy marketplace by increasing pipeline throughput and the mix of products handled through the existing system and establishing new receipt and delivery connections. MB Storage is a service-oriented, fee-based venture with no commodity trading activity. TE Products operates the facilities for MB Storage. Effective January 1, 2003, TE Products contributed property and equipment with a net book value of $67.1 million to MB Storage. Additionally, as of the contribution date, Louis Dreyfus had invested $6.1 million for expansion projects for MB Storage that TE Products was required to reimburse if the original joint development and marketing agreement was terminated by either party. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in MB Storage.

TE Products' interest in MB Storage is not subject to any encumbrances from mortgages or other secured debt. TE Products receives the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement. Any amount of MB Storage's annual income before depreciation expense in excess of $7.15 million is allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based upon the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2004 and 2003, TE Products' sharing ratio in the earnings of MB Storage was approximately 69.4% and 70.4%, respectively. For the years ended December 31, 2004 and 2003, excluding the contribution of property and equipment upon formation of the partnership, TE Products has contributed $21.4 million and $2.5 million, respectively, to MB Storage. The 2004 amount includes a contribution of $16.5 million for the acquisition of storage and pipeline assets in April 2004. The remaining contributions have been for capital expenditures in both periods. During the years ended December 31, 2004 and 2003, TE Products received distributions of $10.3 million and $5.3 million, respectively, from MB Storage.

MB Storage's asset base in the Mont Belvieu fractionation and storage complex, which is the largest complex of its kind in the United States, serving the fractionation, refining and petrochemical industries, provides substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage receives revenue from the shuttling of product from refineries and fractionators to pipelines, refineries and petrochemical facilities on the upper Texas Gulf Coast.

On April 1, 2004, MB Storage acquired storage and pipeline assets at Mont Belvieu from ConocoPhillips for approximately $34.0 million. The acquisition included three salt dome storage wells with a total storage capacity of 5.6 million barrels, various pipeline assets and a 200-acre parcel of property for future expansion. The acquisition also included 2.6 million barrels of brine storage capacity. The acquisition supports MB Storage's strategy of increasing the productivity of the Mont Belvieu assets by expanding its product and service base to include the storage and transportation of ethane and the storage of ethylene.

Including the capacity acquired from ConocoPhillips, MB Storage has approximately 36 million barrels of LPGs storage capacity and approximately 7 million barrels of refined products storage capacity, including storage capacity leased to outside parties, at the Mont Belvieu fractionation and storage complex. MB Storage includes a short-haul transportation shuttle system, consisting of a complex system of pipelines and interconnects, that ties Mont Belvieu to virtually every refinery and petrochemical facility on the upper Texas Gulf Coast. MB Storage also provides truck and rail car loading capability. Total shuttle volumes for the three years ended December 31, 2004, 2003 and 2002, were 39.3 million barrels, 33.1 million barrels and 28.9 million barrels, respectively.

Refined Products, LPGs and Petrochemical Pipeline Systems

TE Products is one of the largest pipeline common carriers of refined petroleum products and LPGs in the United States. The Downstream Segment, primarily through TE Products, owns and operates an approximately 4,600-mile pipeline system (together with the receiving, storage and terminaling facilities mentioned below, the "Products Pipeline System") extending from southeast Texas through the central and midwestern United States to the northeastern United States. The Products Pipeline System includes delivery terminals for outloading product to other pipelines, tank trucks, rail cars or barges, and substantial storage facilities at numerous locations. TE Products also owns one active marine receiving terminal at Providence, Rhode Island. The Providence terminal is not physically connected to the Products Pipeline System. The Products Pipeline System also includes three parallel 12-inch diameter petrochemical pipelines between Mont Belvieu and Port Arthur, each approximately 70 miles in length, and 138 miles of pipeline from Mont Belvieu to Point Comfort (the northern portion of the Dean Pipeline).

All properties comprising the Products Pipeline System are wholly owned by our subsidiaries and none are mortgaged or encumbered to secure funded debt. TE Products has guaranteed up to $75.0 million of Centennial's unsecured debt (see –*Centennial Pipeline Equity Investment* above) and has also guaranteed our unsecured debt (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Condition and Liquidity).

Products are transported in liquid form from the upper Texas Gulf Coast through two parallel underground pipelines that extend to Seymour, Indiana. From Seymour, segments of the Products Pipeline System extend to the Chicago, Illinois; Lima, Ohio; Selkirk, New York; and Philadelphia, Pennsylvania, areas. The Products Pipeline System east of Todhunter, Ohio, is dedicated solely to LPGs transportation and storage services, primarily for propane.

Excluding the storage facilities of Centennial and MB Storage, the Products Pipeline System includes 27 storage facilities with an aggregate storage capacity of 16 million barrels of refined petroleum products and 6 million barrels of LPGs, including storage capacity leased to outside parties. The Products Pipeline System makes deliveries to customers at 56 locations including 19 truck racks, rail car facilities and marine facilities that we own. Deliveries to other pipelines occur at various facilities owned by TE Products or by third parties.

The Products Pipeline System is comprised of a 20-inch diameter line extending in a generally northeasterly direction from Baytown, Texas (located approximately 30 miles east of Houston), to a point in southwest Ohio near Lebanon and Todhunter. A second line, which also originates at Baytown, is 16 inches in diameter until it reaches Beaumont, at which point it reduces to a 14-inch diameter line. This second line extends along the same path as the 20-inch diameter line to the Products Pipeline System's terminal in El Dorado, Arkansas, before continuing as a 16-inch diameter line to Seymour. The Products Pipeline System also has smaller diameter lines that extend laterally from El Dorado to Helena, Arkansas, from Shreveport, Louisiana, to El Dorado and from McRae, Arkansas, to West Memphis, Arkansas. The line from El Dorado to Helena has a 10-inch diameter. The line from Shreveport to El Dorado varies in diameter from 8 inches to 10 inches. The line from McRae to West Memphis has a 12-inch diameter. The Products Pipeline System also includes a 14-inch diameter line from Seymour to Chicago, Illinois, and a 10-inch diameter line running from Lebanon to Lima, Ohio. This 10-inch diameter pipeline connects to the Buckeye Pipe Line Company system that serves, among others, markets in Michigan and eastern Ohio. The Products Pipeline System also has a 6-inch diameter pipeline connection to the Greater Cincinnati/Northern Kentucky International Airport and an 8-inch diameter pipeline connection to the George Bush Intercontinental Airport terminal in Houston. In addition, the Products Pipeline System contains numerous lines, ranging in size from 6 inches to 20 inches in diameter, associated with the gathering and distribution system, extending from Baytown to Beaumont; Texas City to Baytown; Pasadena, Texas, to Baytown and Baytown to Mont Belvieu.

The Products Pipeline System continues eastward from Todhunter, Ohio, to Greensburg, Pennsylvania, at which point it branches into two segments, one ending in Selkirk, New York (near Albany), and the other ending at Marcus Hook, Pennsylvania (near Philadelphia). The Products Pipeline System east of Todhunter and ending in Selkirk is an 8-inch diameter line, and the line starting at Greensburg and ending at Marcus Hook varies in diameter from 6 inches to 8 inches.

In 2003, we increased the delivery capability between Todhunter, Ohio, and Coshocton, Ohio, by 8,000 to 10,000 barrels per day and increased storage and improved loading capability at Oneonta, New York. In 2004, we also completed a Phase II project to further extend beyond Coshocton our delivery capacity of LPGs to the Northeast by 8,000 to 10,000 barrels per day. The Phase II expansion included the construction of three pump stations between Coshocton and Greensburg, Pennsylvania, and two stations from Greensburg to Watkins Glen, New York. Additional work on the pipeline segment between Greensburg and Philadelphia, Pennsylvania, to increase delivery rates to the Philadelphia area has been completed. Improvements were also completed during the fourth quarter of 2004 at our Dubois, Pennsylvania, terminal, and additional improvements are expected to be completed during the first quarter of 2005 at our Eagle, Pennsylvania, terminal.

TE Products also owns three 12-inch diameter common carrier petrochemical pipelines between Mont Belvieu and Port Arthur. Each of these pipelines is approximately 70 miles in length. The pipelines transport ethylene, propylene and natural gasoline. We entered into a 20-year agreement in 2002 with a major petrochemical producer for guaranteed throughput commitments. During the years ended December 31, 2004, 2003, and 2002, we recognized $12.0 million, $11.9 million and $11.9 million, respectively, of revenue under the throughput and deficiency contract.

Our Downstream Segment also includes the operations of the northern portion of the Dean Pipeline. Beginning in January 2003, the northern portion of the Dean Pipeline was converted to transport RGP from Mont

Belvieu to Point Comfort. The northern portion of the Dean Pipeline consists of 138 miles of pipeline from Mont Belvieu to Point Comfort.

We believe that our Products Pipeline System is in compliance with applicable federal, state and local laws and regulations and accepted industry standards and practices. We perform regular maintenance on all of the facilities of the Products Pipeline System and have an ongoing process of inspecting the Products Pipeline System and making repairs and replacements when necessary or appropriate. In addition, we conduct periodic air patrols of the Products Pipeline System to monitor pipeline integrity and third-party right-of-way encroachments.

Major Business Sector Markets

Our major operations in the Downstream Segment consist of the transportation, storage and terminaling of refined petroleum products and LPGs along our mainline system. Product deliveries, in millions of barrels (MMBbls) on a regional basis, for the years ended December 31, 2004, 2003 and 2002, were as follows:

	Years Ended December 31,		
	2004	2003	2002
Refined Products Mainline Transportation:			
Central (1)	69.0	67.0	62.9
Midwest (2)	53.5	57.7	49.6
Ohio and Kentucky	29.9	29.4	25.7
Subtotal	152.4	154.1	138.2
LPGs Mainline Transportation:			
Central, Midwest and Kentucky (1)(2)	27.0	23.4	25.4
Ohio and Northeast (3)	17.0	19.1	15.1
Subtotal	44.0	42.5	40.5
Total Mainline Transportation	196.4	196.6	178.7
Petrochemical Transportation (4)	3.6	3.4	—
Total Product Deliveries	200.0	200.0	178.7

(1) Arkansas, Louisiana, Missouri and Texas.

(2) Illinois and Indiana.

(3) New York and Pennsylvania.

(4) Includes Dean North RGP volumes. Petrochemical transportation between Mont Belvieu and Port Arthur, Texas, has not been included as those volumes are with one customer.

The mix of products delivered varies seasonally. Gasoline demand is generally stronger in the spring and summer months and LPGs demand is generally stronger in the fall and winter months. Weather and economic conditions in the geographic areas served by our Products Pipeline System also affect the demand for, and the mix of, the products delivered.

Refined products and LPGs deliveries in MMBbls for the years ended December 31, 2004, 2003 and 2002, were as follows:

	Years Ended December 31,		
	2004	2003	2002
Refined Products Mainline Transportation:			
Gasoline	89.3	89.8	81.9
Jet Fuels	25.6	26.4	25.3
Distillates (1)	37.5	37.9	31.0
Subtotal	152.4	154.1	138.2
LPGs Mainline Transportation:			
Propane	34.3	34.5	32.9
Butanes	9.7	8.0	7.6
Subtotal	44.0	42.5	40.5
Total Mainline Transportation	196.4	196.6	178.7
Petrochemical Transportation	3.6	3.4	—
Total Product Deliveries	200.0	200.0	178.7

(1) Primarily diesel fuel, heating oil and other middle distillates.

Refined Products Mainline Transportation

Our Products Pipeline System transports refined petroleum products from the upper Texas Gulf Coast, eastern Texas and southern Arkansas to the Central and Midwest regions of the United States with deliveries in Texas, Louisiana, Arkansas, Missouri, Illinois, Kentucky, Indiana and Ohio. At these points, refined petroleum products are delivered to terminals owned by TE Products, connecting pipelines and customer-owned terminals.

The volume of refined petroleum products transported by our Products Pipeline System is directly affected by the demand for refined products in the geographic regions that our system serves. This market demand varies based upon the different end uses to which the refined products deliveries are applied. Demand for gasoline, which accounted for approximately 59% of the volume of refined products transported through the Products Pipeline System during 2004, depends upon price, prevailing economic conditions and demographic changes in the markets that we serve. Demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities, which use distillates as a substitute for natural gas when the price of natural gas is high, and usage for agricultural operations, which is affected by weather conditions, government policy and crop prices. Demand for jet fuel depends upon prevailing economic conditions and military usage.

Market prices for refined petroleum products affect the demand in the markets served by our Downstream Segment. Therefore, quantities and mix of products transported may vary. Transportation tariffs of refined petroleum products vary among specific product types. As a result, market price volatility may affect transportation volumes and revenues from period to period.

LPGs Mainline Transportation

Our Products Pipeline System transports LPGs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States. The Products Pipeline System east of Todhunter, Ohio, is devoted solely to the transportation of LPGs. Because propane demand is generally sensitive to weather in the winter months, year-to-year variations of propane deliveries have occurred and will likely continue to occur. Our Products Pipeline System also transports normal butane and isobutane in the Midwest and Northeast for use in the production of motor gasoline.

Our ability in the Downstream Segment to serve propane markets in the Northeast is enhanced by our marine import terminal at Providence. This facility includes a 400,000-barrel refrigerated storage tank along with ship unloading and truck loading facilities. Effective May 2001, we entered into an agreement with an affiliate of

DEFS to commit to it sole utilization of our Providence terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. The agreement was renegotiated in May 2004. During the years ended December 31, 2004, 2003, and 2002, revenues of $4.3 million, $3.2 million and $2.3 million, respectively, from an affiliate of DEFS were recognized pursuant to this agreement.

Other Operating Revenues

Our Downstream Segment also earns revenue from terminaling activities and other ancillary services associated with the transportation and storage of refined petroleum products and LPGs. From time to time, we sell excess product inventory. Other operating revenues include revenues related to the intrastate transportation of petrochemicals under a throughput and deficiency contract.

Customers

Our customers for the transportation of refined petroleum products include major integrated oil companies, independent oil companies, the airline industry and wholesalers. End markets for these deliveries are primarily retail service stations, truck stops, railroads, agricultural enterprises, refineries and military and commercial jet fuel users.

Propane customers include wholesalers and retailers who, in turn, sell to commercial, industrial, agricultural and residential heating customers, as well as utilities who use propane as a back-up fuel source. Refineries constitute our major customers for butane and isobutane, which are used as a blend stock for gasolines and as a feed stock for alkylation units, respectively.

At December 31, 2004, our Downstream Segment had approximately 139 customers. During the year ended December 31, 2004, total revenues (and percentage of total revenues) attributable to the top 10 customers were $151.7 million (54%), of which Marathon Ashland Petroleum LLC accounted for approximately 17% of total Downstream Segment revenues. During the year ended December 31, 2003, total revenues (and percentage of total revenues) attributable to the top 10 customers were $149.5 million (56%), of which Marathon Ashland Petroleum LLC accounted for approximately 18% of total Downstream Segment revenues. During the year ended December 31, 2002, total revenues (and percentage of total revenues) attributable to the top 10 customers were $101.6 million (51%). During the year ended December 31, 2002, no single customer accounted for 10% or more of total Downstream Segment's revenues. During each of the three years ended December 31, 2004, 2003 and 2002, no single customer of the Downstream Segment accounted for 10% or more of total consolidated revenues.

Credit Policies and Procedures

We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. We utilize letters of credit and guarantees for certain of our receivables. However, these procedures and policies do not fully eliminate customer credit risk. During the year ended December 31, 2004, we expensed a minimal amount of uncollectible receivables of the Downstream Segment. During the years ended December 31, 2003 and 2002, a few small to medium-sized customers of the Downstream Segment filed for bankruptcy protection, and as a result, we expensed approximately $0.8 million and $0.7 million, respectively, of uncollectible receivables of the Downstream Segment related to customer bankruptcies or other non-payments.

Competition

The Products Pipeline System conducts operations without the benefit of exclusive franchises from government entities. Interstate common carrier transportation services are provided through the system pursuant to tariffs filed with the FERC.

Because pipelines are generally the lowest cost method for intermediate and long-haul overland movement of refined petroleum products and LPGs, the Products Pipeline System's most significant competitors (other than indigenous production in its markets) are pipelines in the areas where the Products Pipeline System delivers products. Competition among common carrier pipelines is based primarily on transportation charges, quality of customer service and proximity to end users. We believe our Downstream Segment is competitive with other

pipelines serving the same markets; however, comparison of different pipelines is difficult due to varying product mix and operations.

Trucks, barges and railroads competitively deliver products in some of the areas served by the Products Pipeline System. Trucking costs, however, render that mode of transportation less competitive for longer hauls or larger volumes. Barge fees for the transportation of refined products are generally lower than TE Products' tariffs. We face competition from rail movements of LPGs from Sarnia, Ontario, Canada, and waterborne imports into New Hampshire.

Financial Information about the Downstream Segment

See Note 17. Segment Information in the Notes to the Consolidated Financial Statements for financial information about the Downstream Segment.

Upstream Segment – Gathering, Transportation, Marketing and Storage of Crude Oil

Operations

We conduct business in our Upstream Segment through the following:

- TCTM,
- TEPPCO Crude Pipeline, L.P. ("TCPL"), TEPPCO Crude Oil, L.P. ("TCO") and Lubrication Services, L.P. ("LSI"), wholly owned subsidiaries of TCTM, and
- our 50% owned equity investment in Seaway Crude Pipeline Company ("Seaway").

Our Upstream Segment gathers, transports, markets and stores crude oil, and distributes lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. We commenced our Upstream Segment business in connection with the acquisition of assets from an affiliate of DEFS in November 1998. Our Upstream Segment uses its asset base to aggregate crude oil and provide transportation and specialized services to its regional customers. Our Upstream Segment purchases crude oil from various producers and operators at the wellhead and makes bulk purchases of crude oil at pipeline and terminal facilities. The crude oil is then sold to refiners and other customers. The Upstream Segment transports crude oil through equity owned pipelines, its trucking operations and third party pipelines.

Margins in the Upstream Segment, as used throughout this Report, are calculated as revenues generated from the sale of crude oil and lubrication oil, and transportation of crude oil, less the costs of purchases of crude oil and lubrication oil. Margins are a more meaningful measure of financial performance than sales and purchases of crude oil and lubrication oil due to the significant fluctuations in sales and purchases caused by variations in the level of volumes marketed and prices for products marketed (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Upstream Segment for margin and volume information). Additionally, we use margin internally to evaluate the financial performance of the Upstream Segment as we believe margin is a better indicator of performance than operating income as operating, general and administrative expenses, operating fuel and power and depreciation expense are not directly related to the margin activities.

TCO purchases crude oil and simultaneously establishes a margin by selling crude oil for physical delivery to third party users. We seek to maintain a balanced marketing position until we make physical delivery of the crude oil, thereby minimizing or eliminating our exposure to price fluctuations occurring after the initial purchase. However, certain basis risks, which are the risks that price relationships between delivery points, classes of products or delivery periods will change, cannot be completely hedged or eliminated. Risk management policies have been established by the Risk Management Committee to monitor and control market risks. The Risk Management Committee is comprised, in part, of certain senior executives of the Company.

Product deliveries on TCPL's 100% owned pipeline systems, undivided joint interest pipelines and Seaway for the years ended December 31, 2004, 2003 and 2002, were as follows (in millions):

	Years Ended December 31,		
	2004	**2003**	**2002**
Barrels Delivered:			
Crude oil transportation	101.5	95.5	82.8
Crude oil marketing	177.3	159.7	139.2
Crude oil terminaling	113.2	115.1	127.4
Lubricants and chemicals (total gallons)	14.0	10.4	9.6
Seaway:			
Long-haul	94.3	71.0	62.6
Short-haul	215.8	179.8	183.8

Properties

The major crude oil pipelines and pipeline systems of our Upstream Segment are set forth in the following table, which include pipelines owned jointly with other industry participants or producers:

Crude Oil Pipeline	Our Ownership	Operator	Description
Red River System	100%	TCPL	1,690 miles of pipeline; 1,484,000 barrels of storage – North Texas to South Oklahoma
South Texas System (1)	100%	TCPL	900 miles of pipeline; 780,000 barrels of storage – South Central Texas to Houston, Texas area
West Texas Trunk System	100%	TCPL	250 miles of smaller diameter pipeline – connecting West Texas and Southeast New Mexico to TCPL's Midland, Texas terminal
Seaway (2)	50% general partnership interest	TCPL	500-mile, 30-inch diameter pipeline; 6,320,000 barrels of storage – Texas Gulf Coast to Cushing, Oklahoma
Basin	13% joint ownership	Plains All American Pipeline, L.P.	416-mile pipeline – Permian Basin (New Mexico and Texas) to Cushing, Oklahoma

(1) Includes assets that were previously part of the Rancho Pipeline and our acquisition of the Genesis assets.

(2) TCPL's participation in revenues and expenses of Seaway vary as described below in "*-Seaway Crude Pipeline Equity Investment*."

None of these pipelines or systems are mortgaged or encumbered to secure funded debt. TCTM has provided guarantees of our unsecured debt (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations).

The majority of the Red River System crude oil is delivered to Cushing, Oklahoma, via third party pipelines, or to two local refineries. The majority of the crude oil on the South Texas System is delivered on a tariff basis to Houston area refineries. The West Texas Trunk System is a fee based system which connects gathering systems to TCPL's Midland, Texas terminal. Other crude oil assets, located primarily in Texas and Oklahoma, consist of 310 miles of pipeline and 295,000 barrels of storage capacity.

In connection with our acquisition of ARCO Pipe Line Company ("ARCO"), a wholly owned subsidiary of Atlantic Richfield Company, in 2000, we acquired an approximate 23.5% undivided joint interest in the Rancho Pipeline, which was a crude oil pipeline system from West Texas to Houston. In March 2003, the Rancho Pipeline ceased operations, and segments of the pipeline were sold to certain of the owners that previously held undivided interests in the pipeline. We acquired 241 miles of the pipeline in exchange for cash of $5.5 million and our interests in other portions of the Rancho Pipeline. We sold 183 miles of the segment we acquired to other entities for cash and assets valued at approximately $8.5 million. We recorded a net gain of $3.9 million on the transactions in the second quarter of 2003. During the third quarter of 2004, we sold our remaining interest in the original Rancho Pipeline system for a net gain of $0.4 million. These gains are included in the gains on sales of assets in our consolidated statements of income.

On November 1, 2003, we purchased crude supply and transportation assets along the upper Texas Gulf Coast for $21.0 million from Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. ("Genesis"). The transaction was funded with proceeds from our August 2003 equity offering (see Note 11. Partners' Capital and Distributions). We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets (see Note 5. Acquisitions and Dispositions). The assets acquired included approximately 150 miles of small diameter trunk lines, 26,000 barrels per day of throughput and 12,000 barrels per day of lease marketing and supply business. We have integrated these assets into our South Texas pipeline system, which has allowed us to consolidate gathering and marketing assets in key operating areas in a cost effective manner and will provide future growth opportunities. Accordingly, the results of the acquisition are included in the consolidated financial statements from November 1, 2003.

TCO purchases condensate from DEFS and its affiliates. For the years ended December 31, 2004, 2003, and 2002, TCO's purchases from DEFS and its affiliates were $141.3 million, $110.7 million, and $80.5 million, respectively.

Seaway Crude Pipeline Equity Investment

Seaway is a partnership between a subsidiary of TCTM, TEPPCO Seaway, L.P. ("TEPPCO Seaway"), and ConocoPhillips. TCTM acquired its 50% ownership interest in Seaway on July 20, 2000, as part of its purchase of ARCO. We assumed ARCO's role as operator of this pipeline. The 30-inch diameter, 500-mile pipeline transports crude oil from the U.S. Gulf Coast to Cushing, a central crude distribution point for the central United States and a delivery point for the New York Mercantile Exchange ("NYMEX"). The Freeport, Texas, marine terminal is the origin point for the 30-inch diameter crude pipeline. Three large diameter lines carry crude oil from the Freeport marine terminal to the adjacent Jones Creek Tank Farm, which has six tanks capable of handling approximately 2.6 million barrels of crude oil. A crude oil marine terminal facility at Texas City, Texas, is used to supply refineries in the Houston area. Two pipelines connect the Texas City marine terminal to storage facilities in Texas City and Galena Park, Texas, where there are seven tanks with a combined capacity of approximately 3 million barrels. Seaway has the capability to provide marine terminaling and crude oil storage services for all Houston area refineries.

The Seaway partnership agreement provides for varying participation ratios throughout the life of Seaway. From July 20, 2000, through May 2002, we received 80% of revenue and expense of Seaway. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. For the year ended December 31, 2002, our portion of equity earnings on a pro-rated basis averaged approximately 67%. During the years ended December 31, 2004 and 2003, we received distributions from Seaway of $36.9 million and $22.7 million, respectively.

Line Transfers, Pumpovers and Other

Our Upstream Segment provides trade documentation services to its customers, primarily at Cushing and Midland. TCPL documents the transfer of crude oil in its terminal facilities between contracting buyers and sellers. This line transfer documentation service is related to the trading activity by TCPL's customers of NYMEX open-interest

crude oil contracts and other physical trading activity. This service provides a documented record of receipts, deliveries and transactions to each customer, including confirmation of trade matches, inventory management and scheduled movements. Line transfer revenues are included as part of other operating revenues in our consolidated statements of income.

The line transfer services also attract physical barrels to TCPL's facilities for final delivery to the ultimate owner. A pumpover occurs when the last title transfer is executed and the physical barrels are delivered out of TCPL's custody. TCPL owns and operates storage facilities primarily in Midland and Cushing with an operational capacity of approximately 1.1 million barrels to facilitate the pumpover business. Revenues from pumpover services are included as part of crude oil transportation revenues in our consolidated statements of income and represent the crude oil terminaling component. The line transfer and pumpover operations were acquired as part of our purchase of ARCO in 2000.

LSI distributes lubrication oils and specialty chemicals to natural gas pipelines, gas processors and industrial and commercial accounts. LSI's distribution networks are located in Colorado, Wyoming, Oklahoma, Kansas, New Mexico, Texas and Louisiana. LSI also sells lubrication oils and specialty chemicals to DEFS. For the years ended December 31, 2004, 2003, and 2002, revenues recognized by LSI included $16.1 million, $15.2 million and $14.6 million, respectively, for the sale of lubrication oils and specialty chemicals to DEFS.

Customers

TCO purchases crude oil primarily from major integrated oil companies and independent oil producers. Crude oil sales are primarily to major integrated oil companies and independent refiners. Gross sales revenue of the Upstream Segment attributable to the top 10 customers was $3.8 billion (70%), $2.6 billion (67%) and $1.9 billion (66%) for the years ended December 31, 2004, 2003 and 2002, respectively. For the years ended December 31, 2004, 2003 and 2002, Valero Energy Corp. ("Valero") accounted for 17%, 18% and 18%, respectively, of the Upstream gross sales revenue. For each of the years ended December 31, 2004, 2003 and 2002, Valero accounted for 16% of our total consolidated revenues.

Competition

The most significant competitors in pipeline operations in our Upstream Segment are primarily common carrier and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies and other companies in the areas where our pipeline systems deliver crude oil. Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service, knowledge of products and markets, and proximity to refineries and connecting pipelines. The crude oil gathering and marketing business is characterized by thin margins and intense competition for supplies of crude oil at the wellhead. Declines in domestic crude oil production have intensified competition among gatherers and marketers.

A significant portion of the growth in our Upstream Segment has occurred through acquisitions of pipeline gathering systems. Our acquisitions in this segment have provided increased efficiencies for the gathering and transportation of crude oil with our existing pipeline systems as well as expansion into new market areas. We experience competition from other gatherers and marketers in bidding for potential acquisitions. Within the past few years, the number of companies involved in the gathering of crude oil in the United States has decreased as a result of business consolidations and bankruptcies, which may decrease the number of potential acquisitions of crude gathering systems available to us.

Credit Policies and Procedures

As crude oil or lubrication oils are marketed or transported, we must determine the amount, if any, of credit to be extended to any given customer. Due to the nature of individual sales transactions, risk of non-payment and non-performance by customers is a major consideration in our business. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. We utilize letters of credit and guarantees for certain of our receivables. However, these procedures and policies do not fully eliminate customer credit risk. During the years ended December 31, 2004 and 2002, we expensed approximately $0.1 million and $0.2

million, respectively, of uncollectible receivables of the Upstream Segment. During the year ended December 31, 2003, no additional reserves were necessary for uncollectible receivables of the Upstream Segment.

Financial Information about the Upstream Segment

See Note 17. Segment Information in the Notes to the Consolidated Financial Statements for financial information about the Upstream Segment.

Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs

Operations

We conduct business in our Midstream Segment through the following:

- Jonah Gas Gathering Company (“Jonah”) and Val Verde Gas Gathering Company, L.P. (“Val Verde”), which gather natural gas,

- TEPPCO Midstream and its wholly owned subsidiaries, Chaparral Pipeline Company, L.P. and Quanah Pipeline Company, L.P. (collectively referred to as “Chaparral” or “Chaparral NGL system”), Panola Pipeline Company, L.P. (“Panola Pipeline”), Dean Pipeline Company, L.P. (“Dean Pipeline”) and Wilcox Pipeline Company, L.P. (“Wilcox Pipeline”), which transport NGLs, and

- TEPPCO Colorado, LLC (“TEPPCO Colorado”), which fractionates NGLs.

Revenues of our Midstream Segment are earned from gathering fees based on the volume and pressure of natural gas gathered, transportation of NGLs and fractionation of NGLs in Colorado. Gathering and transportation revenues are recognized as natural gas or NGLs are delivered to customers. Revenues are also earned from the sale of condensate liquid extracted from the natural gas stream to an Upstream Segment marketing affiliate. Fractionation revenues are recognized ratably over the contract year as products are delivered to DEFS. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated; therefore, the results of operations of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs. Our Midstream Segment has multiple long-term contracts with producers connected to the Jonah and Val Verde systems. We cannot influence or control the operation, development or production levels of the gas fields served by the Jonah and Val Verde systems, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

None of these pipelines or systems are mortgaged or encumbered to secure funded debt. TEPPCO Midstream, Jonah and Val Verde have each provided guarantees of our unsecured debt (see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations).

Volume information for the years ended December 31, 2004, 2003 and 2002, is presented below:

	Years Ended December 31,		
	2004	2003	2002
Gathering – Natural Gas – Jonah (billion cubic feet (“Bcf”))	354.5	303.0	248.4
Gathering – Natural Gas – Val Verde (Bcf)	144.5	158.3	92.3
Transportation – NGLs (million barrels)	59.5	57.9	54.0
Fractionation – NGLs (million barrels)	4.1	4.1	4.1

The Jonah Gas Gathering System

On September 30, 2001, we purchased Jonah from Alberta Energy Company for $359.8 million, with an additional payment of $7.3 million made on February 4, 2002, for final purchase adjustments related primarily to construction projects in progress at the time of closing. The acquisition served as our entry into the natural gas gathering industry. Under a contractual agreement, DEFS manages and operates Jonah on our behalf. During the years ended December 31, 2004, 2003 and 2002, we recognized $4.1 million, $3.7 million and $3.3 million, respectively, of expenses related to the operation and management of the Jonah assets by DEFS.

Since the acquisition, we have expanded both the pipeline capacity and processing capacity of the Jonah system. In 2002, we completed the Phase I and Phase II expansions of Jonah, which nearly doubled the capacity of the Jonah system. The Phase I expansion was completed in May 2002 at a cost of approximately $25.0 million and increased system capacity by 62%, from approximately 450 million cubic feet per day ("MMcf/day") to approximately 730 MMcf/day. In October 2002, the Phase II expansion project was completed at a cost of approximately $35.3 million, which increased the capacity of the Jonah system from 730 MMcf/day to approximately 880 MMcf/day. In 2003, the Jonah system was again expanded by a Phase III project to include an 80-mile pipeline loop and 3,700 horsepower of new compression on the system and the building of a new 250 MMcf/day gas processing plant near Opal, Wyoming. Phase III was substantially completed during the fourth quarter of 2003, and the system was operational, with system capacity increasing to 1,180 MMcf/day at a cost of approximately $53.4 million. Additional capacity of 100 MMcf/day was completed during the fourth quarter of 2004, at a cost of approximately $13.0 million. In 2005, a Phase IV expansion project is planned, which is expected to increase system capacity to 1.5 billion cubic feet per day with the addition of 33,300 horsepower and approximately 45 miles of pipeline. The Phase IV expansion is expected to be completed in late 2005 at a cost of approximately $122.0 million.

The Jonah system consists of approximately 500 miles of pipelines ranging in size from three inches to 24 inches in diameter, three compressor stations with an aggregate of approximately 62,000 horsepower and related metering facilities. Gas gathered on the Jonah system is collected from approximately 640 producing wells in southwestern Wyoming's Green River Basin, which is one of the most prolific natural gas basins in the United States. The system also includes two processing facilities that extract condensate prior to delivery of natural gas to DEFS, Northwest, Kern River and Questar. Gas is also delivered to gas processing facilities owned by others. From these processing facilities, the natural gas is delivered to several interstate pipeline systems located in the region for transportation to end-use markets throughout the Midwest, the West Coast and the Rocky Mountain regions. Interstate pipelines in the region include Kern River, Northwest, Colorado Interstate Gas and Questar.

Jonah provides gas gathering services to an affiliate of DEFS. The gathering fees paid to us by an affiliate of DEFS totaled $3.3 million, $2.0 million, and $1.2 million for the years ended December 31, 2004, 2003 and 2002, respectively. In connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004, Jonah sells NGLs to, and purchases gas from, an affiliate of DEFS. For the year ended December 31, 2004, Jonah's sales to DEFS and its affiliates were $7.1 million, and purchases from DEFS and its affiliates were $5.1 million. In addition, the processing fees we received from an affiliate of DEFS for gas processing services at the Pioneer plant totaled $0.6 million for the year ended December 31, 2004.

The Val Verde Gas Gathering System

On June 30, 2002, we purchased Val Verde for $444.2 million from Burlington Resources Gathering Inc., a subsidiary of Burlington Resources Inc., including acquisition related costs of approximately $1.2 million. We funded the purchase primarily through borrowings under bank credit facilities. We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets for gas gathering contracts (see Note 5. Acquisitions and Dispositions). We accounted for the acquisition of these assets under the purchase method of accounting. Accordingly, the results of the acquisition have been included in our consolidated financial statements from June 30, 2002. Under a contractual agreement, DEFS manages and operates Val Verde on our behalf. During the years ended December 31, 2004, 2003, and 2002, we recognized $3.8 million, $3.0 million and $1.2 million, respectively, of expenses related to the operation and management of the Val Verde assets by DEFS.

The Val Verde system consists of approximately 400 miles of pipeline ranging in size from four inches to 36 inches in diameter, 14 compressor stations operating over 93,000 horsepower of compression and a large amine treating facility for the removal of carbon dioxide. The system has a pipeline capacity of approximately one billion cubic feet of gas per day. The Val Verde system gathers coal bed methane ("CBM") from the Fruitland Coal Formation of the San Juan Basin in New Mexico and Colorado, a long-term source of natural gas supply in North

America. The basin is one of the most prolific sources of CBM and also contains significant conventional gas reserves. The system is one of the largest CBM gathering and treating facilities in the United States, gathering CBM from more than 500 separate wells throughout northern New Mexico and southern Colorado, and provides gathering and treating services pursuant to 60 long-term contracts with approximately 40 different natural gas producers in the San Juan Basin. Gas transported on the Val Verde system is delivered to several interstate pipeline systems serving the western United States, as well as local New Mexico markets.

In December 2004, we completed a project to connect Val Verde with a third party gathering system originating in Colorado. Val Verde constructed approximately 16 miles of pipeline and entered into a multi-year agreement to transport and treat natural gas. Natural gas from this interconnection will increase the utilization of Val Verde's capacity by up to 125 MMcf/day. Val Verde transported and treated an average of 40 MMcf/day of natural gas in December 2004 and received a nomination to handle 80 MMcf/day of natural gas starting in January 2005.

In July 2003, the New Mexico Oil Conservation Division approved an application for infill drilling to allow two wells per standard 320-acre gas spacing unit in the Fruitland Coal Formation of the San Juan Basin. This approval of infill drilling will provide potential opportunities for long-term growth and increased throughput on the Val Verde system.

NGL Transportation and Fractionation

The NGL pipelines of the Midstream Segment are located along the Texas Gulf Coast, East Texas and from southeastern New Mexico and West Texas to Mont Belvieu. They are all wholly owned and operated by either our subsidiaries or under a contractual agreement with DEFS. Information about these NGL pipelines is set forth in the following table:

NGL Pipeline	Capacity (barrels/day)	Description
Chaparral	135,000	845 miles of pipeline – West Texas and New Mexico to Mont Belvieu, Texas
Quanah	22,000	180 miles of pipeline – Sutton County, Texas to the Chaparral Pipeline near Midland, Texas

Panola	43,000	189 miles of pipeline – Carthage, Texas to Mont Belvieu, Texas
San Jacinto	12,000	34 miles of pipeline – Carthage, Texas to Longview, Texas
The southern portion of the Dean Pipeline	10,000	155 miles of pipeline – South Texas to Point Comfort, Texas
Wilcox	7,500	103 miles of pipeline – Southeast Texas

On March 1, 2002, we purchased the Chaparral NGL system for $132.4 million from Diamond-Koch II, L.P. and Diamond-Koch III, L.P., including acquisition related costs of approximately $0.4 million. The Chaparral NGL system extends from West Texas and New Mexico to Mont Belvieu. The pipeline delivers NGLs to fractionators and to MB Storage's existing storage facilities in Mont Belvieu. We funded the purchase through borrowings under a bank credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. Accordingly, the results of the acquisition have been included in our consolidated financial statements from March 1, 2002. Under a contractual agreement, DEFS manages and operates Chaparral on our behalf. During the years ended December 31, 2004, 2003 and 2002, we recognized $2.3 million, $2.1 million and $1.7 million, respectively, of expenses related to the operation and management of the Chaparral assets by DEFS. An affiliate of DEFS transports NGLs on the Chaparral NGL system. The fees paid to us by an affiliate of DEFS for NGL transportation on the Chaparral NGL system totaled $3.8 million, $5.5 million and $4.5 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The Panola Pipeline and San Jacinto Pipeline originate at DEFS' East Texas Plant Complex in Panola County, Texas, and transport NGLs for DEFS and other major integrated oil and gas companies. Revenues recognized from an affiliate of DEFS for NGL transportation totaled $11.3 million, $9.2 million and $12.0 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The southern portion of the Dean Pipeline originates in South Texas and transports NGLs for DEFS into its pipeline in Point Comfort, Texas. Revenues recognized from DEFS for NGL transportation totaled $0.2 million, $1.0 million and $2.9 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The Wilcox Pipeline transports NGLs for DEFS from two of its natural gas processing plants and is currently supported by a throughput agreement with DEFS through November 2005. The fees paid to us by DEFS under the agreement were $1.4 million, $1.5 million and $1.2 million for the years ended December 31, 2004, 2003 and 2002, respectively.

TEPPCO Colorado has two NGL fractionation facilities which separate NGLs into individual components. TEPPCO Colorado is currently supported by a fractionation agreement with DEFS through 2018, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Revenues recognized from the fractionation facilities totaled $7.5 million, $7.4 million and $7.4 million for the years ended December 31, 2004, 2003 and 2002, respectively. Under an operation and maintenance agreement, DEFS also operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS. Expenses related to the Operation and Maintenance Agreement totaled $0.9 million for each of the years ended December 31, 2004, 2003 and 2002.

Customers

The Midstream Segment's customers for the gathering of natural gas include major integrated oil and gas companies and large to medium-sized independent producers. Natural gas from Jonah and Val Verde is delivered into major interstate gas pipelines for delivery primarily to markets in the western United States. The Midstream Segment's customers for the transporting of NGLs include DEFS and its affiliates and other major integrated oil and gas companies. Condensate sales from the Jonah system are primarily to an Upstream Segment marketing affiliate.

At December 31, 2004, the Midstream Segment had approximately 75 customers. Revenue attributable to the top 10 customers was $172.8 million (83%) for the year ended December 31, 2004, of which EnCana Corporation (formerly Alberta Energy Company), DEFS and its affiliates and Burlington Resources Inc. accounted for approximately 21%, 18% and 16%, respectively, of revenues of the Midstream Segment. At December 31, 2003, the Midstream Segment had approximately 70 customers. Revenue attributable to the top 10 customers was $155.9 million (84%) for the year ended December 31, 2003, of which EnCana Corporation, Burlington Resources Inc. and DEFS and its affiliates accounted for approximately 21%, 18% and 14%, respectively, of revenues of the Midstream Segment. At December 31, 2002, the Midstream Segment had approximately 70 customers. Revenue attributable to the top 10 customers was $117.5 million (85%) for the year ended December 31, 2002, of which DEFS and its affiliates, EnCana Corporation and Burlington Resources Inc. accounted for approximately 21%, 19% and 15%, respectively, of revenues of the Midstream Segment. During each of the three years ended December 31, 2004, 2003 and 2002, no single customer of the Midstream Segment accounted for 10% or more of total consolidated revenues.

Credit Policies and Procedures

We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. We utilize letters of credit and guarantees for certain of our receivables. However, these procedures and policies do not fully eliminate customer credit risk. During the years ended December 31, 2004, 2003 and 2002, no additional reserves were necessary for uncollectible receivables of the Midstream Segment. In December 2001, we expensed approximately $4.3 million of uncollected transportation deficiency revenues due to the bankruptcy of Enron Corp. and certain of its subsidiaries, which occurred in December 2001. During the second quarter of 2004, we sold our Enron Corp. receivable and received $0.6 million.

Competition

The most significant competition for the NGL pipeline operations of our Midstream Segment comes from proprietary pipelines owned and operated by major oil and gas companies and other large independent pipeline companies with contiguous operations. The ability to compete in the NGL pipeline area is based primarily on the quality of customer service and knowledge of products and markets.

The majority of the recent growth in the Midstream Segment is due to the acquisition and expansions of Jonah in the Green River Basin in southwestern Wyoming and the acquisition of Val Verde in the San Juan Basin in New Mexico and Colorado. Typically, new supplies of natural gas are necessary to offset the natural declines in production from wells connected to any gathering system. The Jonah and Pinedale fields that are the focus of the Jonah system in Wyoming are both relatively young producing areas, characterized by long-lived production profiles with many years of significant growth potential ahead.

Competition in the natural gas gathering operations of our Midstream Segment is based largely on reputation, efficiency, system reliability and system capacity. Key competitors in the gathering and treating segment include independent gas gatherers as well as other major integrated energy companies. Alternate gathering facilities may be available to producers served by our Midstream Segment, and those producers could also elect to construct proprietary gas gathering systems. Success in the gas gathering and treating business segment is based primarily on a thorough understanding of the needs of the producers served, as well as a strong commitment to providing responsive, high-quality customer service.

If the production ultimately delivered to one of our gathering systems declines, revenues from such operations would also be adversely affected. If these declines are sustained or substantial, we could experience a material adverse effect on our financial position, results of operations or cash flows.

Financial Information about the Midstream Segment

See Note 17. Segment Information in the Notes to the Consolidated Financial Statements for financial information about the Midstream Segment.

Title to Properties

We believe we have satisfactory title to all of our assets. The properties are subject to liabilities in certain cases, such as customary interests generally contracted in connection with acquisition of the properties, liens for taxes not yet due, easements, restrictions and other minor encumbrances. We believe none of these liabilities materially affect the value of our properties or our interest in the properties or will materially interfere with their use in the operation of our business.

Capital Expenditures

Capital expenditures, excluding acquisitions, totaled $164.1 million for the year ended December 31, 2004. Revenue generating projects include those projects which expand service into new markets or expand capacity into current markets. Capital expenditures to sustain existing operations include projects required by regulatory agencies or required life-cycle replacements. System upgrade projects improve operational efficiencies or reduce cost. We capitalize interest costs incurred during the period that construction is in progress. The following table identifies capital expenditures by segment for the year ended December 31, 2004 (in millions):

	Revenue Generating	Sustaining Existing Operations	System Upgrades	Capitalized Interest	Total
Downstream Segment	$ 40.7	$ 29.5	$ 9.4	$ 1.3	$ 80.9
Midstream Segment	40.6	1.1	1.2	2.2	45.1
Upstream Segment	23.1	10.9	2.7	0.7	37.4
Other	—	0.3	0.4	—	0.7
Total	$ 104.4	$ 41.8	$ 13.7	$ 4.2	$ 164.1

Revenue generating capital spending by the Downstream Segment totaled $40.7 million and was used primarily for the expansion of our pipelines extending from Seymour to Indianapolis, Indiana, further expansions of our Northeast pipeline system and construction of a new truck loading terminal in Bossier City, Louisiana. Revenue generating capital spending by the Midstream Segment totaled $40.6 million and was used primarily for the expansion of the Jonah system, new connections to the Red Cedar and Black Hills gathering systems on the Val Verde system and additional well connections on both the Jonah and Val Verde systems. Revenue generating capital spending by the Upstream Segment totaled $23.1 million and was used primarily for the expansion of our South Texas system and connections to various other production facilities and pipelines. In order to sustain existing operations, we spent $29.5 million for various Downstream Segment pipeline projects, $1.1 million for the Midstream Segment and $10.9 million for Upstream Segment facilities. An additional $13.7 million was spent on system upgrade projects among all of our business segments.

We estimate that capital expenditures, excluding acquisitions, for 2005 will be approximately $236.0 million (which includes $6.0 million of capitalized interest). We expect to spend approximately $168.0 million for revenue generating projects and facility improvements. Capital spending on revenue generating projects and facility improvements will include approximately $23.0 million for the expansion of our Downstream Segment facilities. We expect to spend $5.0 million to expand our Upstream Segment pipelines and facilities in West Texas and Oklahoma and approximately $140.0 million to expand our Midstream Segment assets, with further expansions on our Jonah system. We expect to spend approximately $44.0 million to sustain existing operations, including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $18.0 million to improve operational efficiencies and reduce costs among all of our business segments. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

Regulation

Our interstate common carrier pipeline operations are subject to rate regulation by the FERC under the provisions of the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated thereunder. FERC regulation requires that interstate petroleum products and crude oil pipeline rates be posted publicly and that these rates be “just and reasonable” and nondiscriminatory.

Rates of interstate petroleum products and crude oil pipeline companies, like us, are currently regulated by the FERC primarily through an index methodology, which allows a pipeline to change its rates based on the change from year to year in the Producer Price Index for finished goods (“PPI Index”).

Effective as of February 24, 2003, FERC Order on Remand modified the PPI Index from PPI – 1% to PPI. On April 22, 2003, several shippers filed a petition in the United States Court of Appeals for the District of Columbia Circuit (the "Court"), *Flying J. Inc., Lion Oil Company, Sinclair Oil Corporation and Tesoro Refining and Marketing Company vs. Federal Energy Regulatory Commission*, Docket No. 03-1107, seeking a review of whether the FERC's adoption of the PPI Index was reasonable and supported by the evidence. On April 9, 2004, the Court handed down a decision denying the shippers' petition for review, stating the shippers failed to establish that any of FERC's methodological choices (or combination of choices) were both erroneous and harmful.

As an alternative to using the PPI Index, interstate petroleum products and crude oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements between shippers and petroleum products and crude oil pipeline companies that the rate is acceptable.

TE Products has been granted permission by the FERC to utilize Market-Based Rates for all of its refined products movements other than the Little Rock, Arkansas, Arcadia and Shreveport-Arcadia, Louisiana destination markets, which are currently subject to the PPI Index. With respect to LPG movements, TE Products uses the PPI Index. All interstate transportation movements of crude oil by TCPL are subject to the PPI Index as are the NGL interstate transportation movements on the Chaparral NGL system.

On March 26, 2004, an initial decision in *ARCO Products Co., et al. v. SFPP*, Docket OR96-2-000, et al. was issued by the FERC, which made several significant determinations with respect to finding "changed circumstances" under the Energy Policy Act of 1992 ("EP Act"). The decision largely clarifies, but does not fully quantify, the standard required for a complainant to demonstrate that an oil pipeline's rates are no longer subject to the rate protection of the EP Act by demonstrating that a substantial change in circumstances has occurred since 1992 with respect to the basis of the rates being challenged. In the decision, the FERC found that a limited number of rate elements will significantly affect the economic basis for a pipeline company's rates. The elements identified in the decision are volume changes, allowed total return and total cost-of-service (including major cost elements of rate base such as tax rates and tax allowances, among others). The FERC did reject, however, the use of changes in tax rate and income tax allowances as standalone factors. It appears likely that the decision will be appealed. We have not yet determined the impact, if any, that the decision, if it is ultimately upheld, would have on our rates if they were reviewed under the criteria of this decision.

On July 20, 2004, the Court of Appeals for the District of Columbia Circuit issued an opinion in *BP West Coast Producers LLC v. FERC*. In reviewing a series of orders involving SFPP, L.P. the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for 42.7% of the net operating (pre-tax) income expected from operations and was denied an income tax allowance equal to 57.3% of its limited partnership interests that were held by non-corporate partners. The court remanded the case back to the FERC for further review. As a result of the court's remand, the FERC on December 2, 2004, issued a Request for Comments seeking comments on whether the court's ruling applies only to the specific facts of the SFPP, L.P. proceeding or also extends to other capital structures involving partnerships and other forms of ownership. The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

The natural gas gathering operations of the Jonah and Val Verde systems are exempt from FERC regulation under the Natural Gas Act of 1938 since they are intrastate gas gathering systems rather than interstate transmission pipelines. However, the FERC regulation still significantly affects the Midstream Segment, directly or indirectly, by its influences on the parties that produce the natural gas gathered on the Jonah and Val Verde systems. In addition, in recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue the pro-competition policies as it considers pipeline rate case proposals, revisions to rules and policies that affect shipper rights of access to interstate natural gas transportation capacity or proposals by natural gas pipelines to allow natural gas pipelines to charge negotiated rates without rate ceiling limits, such policy changes could have an adverse effect on the gathering rates the Midstream Segment is able to charge in the future.

Environmental Matters

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of injunctions delaying or prohibiting certain activities and the need to perform investigatory and remedial activities. Although we believe our operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure you that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental laws and regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us. We believe that changes in environmental laws and regulations will not have a material adverse effect on our financial position, results of operations or cash flows in the near term.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act ("CWA"), and analogous state laws impose strict controls against the discharge of oil and its derivatives into navigable waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities

and imposes substantial potential liability for the costs of removing petroleum or other hazardous substances. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in navigable waters or into groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent a petroleum tank release from impacting navigable waters.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems as a result of past operations, 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 assure you that the effect will not be material in the aggregate.

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 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 appropriate federal agency being either the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety ("OPS") or the Environmental Protection Agency ("EPA"). Numerous states have enacted laws similar to OPA. Under OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resource damages.

The EPA has adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate. These permits may require us to monitor and sample the storm water run-off.

Air Emissions

Our operations are subject to the federal Clean Air Act (the "Clean Air Act") and comparable state laws. Amendments to 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 future capital expenditures in connection with the addition or modification of 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. The Clean Air Act requires federal operating permits for major sources of air emissions. Under this program, a federal operating permit (a "Title V" permit) may be issued. The permit acts as an umbrella that includes other federal, state and local preconstruction and/or operating permit provisions, emission standards, grandfathered rates and record keeping, reporting and monitoring requirements in a single document. The federal operating permit is the tool that the public and regulatory agencies use to review and enforce a site's compliance with all aspects of clean air regulation at the federal, state and local level. We have completed applications for the facilities for which these regulations apply.

Risk Management Plans

We are subject to the EPA's Risk Management Plan ("RMP") regulations at certain locations. This regulation is intended to work with the Occupational Safety and Health Act ("OSHA") Process Safety Management regulation (see "Safety Matters" below) to minimize the offsite consequences of catastrophic releases. The regulation requires a regulated source, in excess of threshold quantities, to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis, a prevention program and an emergency response program. We believe the operating expenses of the RMP regulations will not have a material adverse effect on our financial position, results of operations or cash flows.

Solid Waste

We generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. 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 wastes meet certain treatment

standards or the land-disposal method meets certain waste containment criteria. From time to time, the EPA considers the adoption of stricter disposal standards for non-hazardous wastes, including crude oil and gas wastes. The adoption of such stricter standards for non-hazardous wastes, or any future re-designation of non-hazardous wastes as hazardous wastes will likely increase our operating expenses as well as for the industry in general.

Superfund

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 and companies that disposed or arranged for the disposal of the 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 ordinary 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.

Other Environmental Proceedings

In 1994, the Louisiana Department of Environmental Quality ("LDEQ") issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. At December 31, 2004, we have an accrued liability of $0.2 million for remediation costs at our Arcadia facility. Effective in March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On March 17, 2003, we experienced a release of 511 barrels of jet fuel from a storage tank at our Blue Island terminal located in Cook County, Illinois. As a result of the release, we have entered into an Agreed Order with the State of Illinois, which required us to conduct an environmental investigation. At this time, we have complied with the terms of the Agreed Order, and the results of the environmental investigation indicated there were no soil or groundwater impacts from the release. We are in the process of negotiating a final settlement with the State of Illinois, and we do not expect that compliance with the settlement will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 22, 2004, we experienced a release of approximately 12 barrels of jet fuel from a sump at our Lebanon, Ohio, terminal. The released jet fuel was contained within a storm water retention pond located on the terminal property. Six migratory waterfowl were affected by the jet fuel and were subsequently euthanized by or at the request of the United States Fish and Wildlife Service ("USFWS"). On October 1, 2004, the USFWS served us with a Notice of Violation, alleging that we violated 16 USC 703 of the Migratory Bird Treaty Act for the "take[ing] of migratory birds by illegal methods." On February 7, 2005, we entered into a Memorandum of Understanding with the USFWS, settling all aspects of this matter. The terms of this settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the EPA, is seeking a civil penalty against us for alleged violations of the CWA arising out of this release. The maximum statutory penalty calculated for this alleged violation of the CWA is $2.8 million. We are in discussions with the

DOJ regarding this matter and have responded to its request for additional information. We do not expect a civil penalty, if any, to have a material adverse effect on our financial position, results of operations or cash flows.

At December 31, 2004, we have an accrued liability of $5.0 million, related to various TCTM and TE Products sites requiring environmental remediation activities. At December 31, 2003, we had an accrued liability of $5.9 million related to various TCTM sites requiring environmental remediation activities. Under the terms of a 1998 agreement through which we acquired various crude oil assets from DETTCO, we received a five year contractual indemnity obligation for certain environmental liabilities attributable to the operations of the assets prior to our acquisition. Concurrent with the expiration of this indemnity in 2003, we entered into a Settlement Agreement and Release with DETTCO releasing DETTCO from future obligations pertaining to certain environmental liabilities, requiring us to share in certain costs for the remediation of a crude oil site in Oklahoma, and the assumption of responsibility by DETTCO for environmental liabilities associated with three sites located in Texas and Oklahoma. We do not expect that the completion of remediation programs associated with TCTM and TE Products activities will have a future material adverse effect on our financial position, results of operations or cash flows.

DOT Pipeline Compliance 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 and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the Secretary of Transportation. The HLPSA was reauthorized in 2002. 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. A written qualification program was completed in April 2001, and our employees performing a covered task were qualified by the October 2002 deadline. 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 with greater than 500 miles of pipeline should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCA"). HCA are defined as 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 developed an IMP by the March 31, 2002 deadline. The regulations require that initial HCA baseline integrity assessments must be conducted within seven years, with all subsequent assessments conducted on a five-year cycle. Additionally, 50% of all HCA pipeline miles must have been assessed by September 30, 2004. We exceeded this requirement by the imposed deadline. In 2003 and 2004, we continued with the baseline evaluation efforts initiated in 2002 and completed the assessment of approximately 1,300 and 2,070 miles, respectively, of our pipeline system. In accordance with our IMP program, we perform the appropriate repairs following each assessment.

Safety Matters

We 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.

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. 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 a flammable liquid or gas, as defined in the regulations, stored on-site in one location, in a quantity of 10,000 pounds or more. We utilize certain covered processes and maintain storage of LPGs in pressurized tanks, caverns and wells, in excess of 10,000 pounds at various locations.

Flammable liquids stored in atmospheric tanks below their normal boiling point without benefit of chilling or refrigeration are exempt. We believe we are in material compliance with the OSHA regulations.

In general, we expect to increase our expenditures during the next decade to comply with stricter industry and regulatory safety standards such as those described above. While such expenditures cannot be accurately estimated at this time, we do not believe that they will have a future material adverse effect on our financial position, results of operations or cash flows.

Employees

The Partnership does not have any employees. However, for organizational purposes, TEPPCO GP, TEPPCO NGL Pipelines, LLC and TEPPCO Crude GP, LLC have officers and directors, who are employees of the General Partner. The General Partner is responsible for the management of us and our subsidiaries. As of December 31, 2004, the General Partner had 1,104 employees. None of the employees of our General Partner were represented by labor unions, and our General Partner considers its employee relations to be good.

Available Information

We file annual, quarterly and other reports and other information with the Securities and Exchange Commission ("SEC") under the Securities Exchange Act of 1934 (the "Exchange Act"). You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site (http://www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

We also make available free of charge on or through our Internet website (http://www.teppco.com) or through our Investor Relations Department (1-800-659-0059) our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other information statements and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 3. ***Legal Proceedings***

In the fall of 1999 and on December 1, 2000, the General Partner and the Partnership were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership) and *Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership). In both cases, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaints, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On January 27, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs and the Richards plaintiffs dismissing all of these plaintiffs' claims. The settlement terms include a $2.0 million payment to the plaintiffs, which has been accrued for in our consolidated

financial statements. The terms of the settlements did not have a material adverse effect on our financial position, results of operations or cash flows.

Although we did not settle with all plaintiffs and we therefore remain named parties in the *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed to indemnify us for all remaining claims asserted against us. Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs have not stipulated the amount of damages they are seeking in the suit; however, this case is covered by insurance. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In May 2003, the General Partner was named as a defendant in a lawsuit styled *John R. James, et al. v. J Graves Insulation Company, et al.* as filed in the first Judicial District Court, Caddo Parish, Louisiana. There are numerous plaintiffs identified in the action that are alleged to have suffered damages as the result of alleged exposure to asbestos-containing products and materials. According to the petition and as a result of a preliminary investigation, the General Partner believes that the only claim asserted against it results from one individual for the period from July 1971 through June 1972, who is alleged to have worked on a facility owned by the General Partner's predecessor. This period represents a small portion of the total alleged exposure period from January 1964 through December 2001 for this individual. The individual's claims involve numerous employers and alleged job sites. The General Partner has been unable to confirm involvement by the General Partner or its predecessors with the alleged location, and it is uncertain at this time whether this case is covered by insurance. Discovery is planned, and the General Partner intends to defend itself vigorously against this lawsuit. The plaintiffs have not stipulated the amount of damages that they are seeking in this suit. We are obligated to reimburse the General Partner for any costs it incurs related to this lawsuit. We cannot estimate the loss, if any, associated with this pending lawsuit. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On April 2, 2003, Centennial was served with a petition in a matter styled *Adams, et al. v. Centennial Pipeline Company LLC, et al*. This matter involves approximately 2,000 plaintiffs who allege that over 200 defendants, including Centennial, generated, transported, and/or disposed of hazardous and toxic waste at two sites in Bayou Sorrell, Louisiana, an underground injection well and a landfill. The plaintiffs allege personal injuries, allergies, birth defects, cancer and death. The underground injection well has been in operation since May 1976. Based upon current information, Centennial appears to be a *de minimis* contributor, having used the disposal site during the two month time period of December 2001 to January 2002. Marathon has been handling this matter for Centennial under its operating agreement with Centennial. TE Products has a 50% ownership interest in Centennial. On November 30, 2004, the court approved a class settlement. The time period for parties to appeal this settlement has not expired, however, and the settlement will not be final until it does so. If the approved class settlement becomes final, the terms of the settlement will not have a material adverse effect on our financial position, results of operations or cash flows.

On December 16, 2003, Centennial, the General Partner, the Partnership and other Partnership entities were named as defendants in a lawsuit in the 128th District Court of Orange County, Texas, styled *Elwood Karr et al. v. Centennial Pipeline, LLC et al*. In this case, the plaintiffs contend that our pipeline leaked toxic substances on their property, causing them property damage. On October 29, 2004, the parties entered into a Settlement Agreement, dismissing all claims. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

On February 4, 2005, we received a letter notifying us of a claim for approximately $1.45 million in damages allegedly due to a shipper being delivered off-specification gasoline during November 2004. We are contesting liability for this matter, and to the extent there may be liability, we would seek reimbursement from the third party refiner who supplied the gasoline into our pipeline system. We do not believe that the outcome of this matter will have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

On February 7, 2005, we received a letter from BP Amoco's counsel placing us on notice of a lawsuit filed by ConocoPhillips against BP Amoco Seaway Products Pipeline Company. Pursuant to provisions of the Amended and Restated Purchase Agreement dated May 10, 2000, between us and ARCO (BP Amoco), BP Amoco requested indemnity should BP Amoco have any liability to ConocoPhillips. The litigation arises out of an income tax liability alleged by ConocoPhillips due to a partnership merger. The plaintiff estimates the income tax liability to be $3,964,788. We have requested information from BP Amoco that will allow us to assess liability, if any, that we may have in this matter. We do not believe that the outcome of this lawsuit will have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

In addition to the litigation discussed above, we have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by

insurance. We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

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

None.

PART II

Item 5. ***Market for Registrant's Units and Related Unitholder Matters***

Our Units are listed and traded on the New York Stock Exchange under the symbol "TPP". The high and low trading prices of our Units in 2004 and 2003, respectively, as reported in *The New York Times*, were as follows:

	2004		2003	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 41.99	$ 34.50	$ 31.64	$ 28.05
Second	42.05	32.75	37.00	30.35
Third	41.75	37.96	37.69	34.00
Fourth	42.36	37.44	41.15	35.22

On February 25, 2005, the closing market price for our Units was $43.10 per Unit. Based on the information received from our transfer agent and from brokers and nominees, we estimate the number of beneficial holders of our Units as of February 25, 2005, to be approximately 73,000.

The quarterly cash distributions for the years ended December 31, 2004 and 2003, were as follows:

Record Date	**Payment Date**	**Amount Per Unit**
April 30, 2003	May 9, 2003	$ 0.625
July 31, 2003	August 8, 2003	0.625
October 31, 2003	November 7, 2003	0.650
January 30, 2004	February 6, 2004	0.650
April 30, 2004	May 7, 2004	$ 0.6625
July 30, 2004	August 6, 2004	0.6625
October 29, 2004	November 5, 2004	0.6625
January 31, 2005	February 7, 2005	0.6625

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Pursuant to the Partnership Agreement, the Company receives incremental incentive cash distributions when cash distributions exceed certain target thresholds (see Note 11. Partner's Capital and Distributions).

We are a publicly traded master limited partnership and are not subject to federal income tax. Instead, unitholders are required to report their allocated share of our income, gain, loss, deduction and credit, regardless of whether we make distributions. We have made quarterly distribution payments since May 1990.

Distributions of cash paid by us to a unitholder will not result in taxable gain or income except to the extent the aggregate amount distributed exceeds the tax basis of the Units owned by the unitholder.

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

The following tables set forth, for the periods and at the dates indicated, our selected consolidated financial and operating data. The financial data was derived from our consolidated financial statements and should be read in conjunction with our audited consolidated financial statements included in the Index to Consolidated Financial Statements on page F-1 of this Report. See also Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	Years Ended December 31,				
	2004	2003	2002 (1)	2001 (2)	2000 (3)
	(in thousands, except per Unit amounts)				
Income Statement Data:					
Operating revenues:					
Sales of petroleum products	$ 5,434,127	$ 3,766,651	$ 2,823,800	$ 3,219,816	$ 2,821,943
Transportation – Refined products	148,166	138,926	123,476	139,315	119,331
Transportation – LPGs	87,050	91,787	74,577	77,823	73,896
Transportation – Crude oil	37,177	29,057	27,414	24,223	17,524
Transportation – NGLs	41,204	39,837	38,870	20,702	7,009
Gathering – Natural gas	140,122	135,144	90,053	8,824	—
Mont Belvieu operations	—	—	15,238	14,116	13,334
Other revenues	70,346	54,430	48,735	51,594	34,904
Total operating revenues	5,958,192	4,255,832	3,242,163	3,556,413	3,087,941
Purchases of petroleum products	5,372,971	3,711,207	2,772,328	3,172,805	2,793,643
Operating expenses	286,247	255,437	213,556	185,918	150,149
Depreciation and amortization	112,894	100,728	86,032	45,899	35,163
Gains on sales of assets	(1,053)	(3,948)	—	—	—
Operating income	187,133	192,408	170,247	151,791	108,986
Interest expense – net	(72,053)	(84,250)	(66,192)	(62,057)	(44,423)
Equity earnings	25,981	16,863	11,980	17,398	12,214
Other income – net	1,320	748	1,827	1,999	599
Net income (as reported)	142,381	125,769	117,862	109,131	77,376
Amortization of goodwill and excess investment	—	—	—	2,396	767
Adjusted net income	$ 142,381	$ 125,769	$ 117,862	$ 111,527	$ 78,143
Basic and diluted income per Unit: (4)					
As reported	$ 1.61	$ 1.52	$ 1.79	$ 2.18	$ 1.89
Amortization of goodwill and excess investment	—	—	—	0.05	0.02
Adjusted net income per Unit	$ 1.61	$ 1.52	$ 1.79	$ 2.23	$ 1.91

	December 31,				
	2004	2003	2002 (1)	2001 (2)	2000 (3)
	(in thousands)				
Balance Sheet Data:					
Property, plant and equipment – net	$ 1,703,702	$ 1,619,163	$ 1,587,824	$ 1,180,461	$ 949,705
Total assets	3,197,705	2,940,992	2,768,422	2,065,348	1,622,810
Long-term debt (net of current maturities)	1,480,226	1,339,650	1,377,692	715,842	835,784
Total debt	1,480,226	1,339,650	1,377,692	1,075,842	835,784
Class B Units held by related party	—	—	103,363	105,630	105,411
Partners' capital	1,021,448	1,109,321	891,842	543,181	315,057

	Years Ended December 31,				
	2004	2003	2002 (1)	2001 (2)	2000 (3)
	(in thousands, except per Unit amounts)				
Cash Flow Data:					
Net cash provided by operating activities	$ 266,210	$ 239,354	$ 234,917	$ 169,148	$ 108,045
Capital expenditures to sustain existing operations	(41,733)	(32,864)	(21,978)	(18,578)	(21,859)
Distributions paid	(233,057)	(202,498)	(151,853)	(104,412)	(82,231)
Distributions paid per Unit (4)	$ 2.64	$ 2.50	$ 2.35	$ 2.15	$ 2.00

(1) Data reflects the operations of the Chaparral and Val Verde assets acquired on March 1, 2002 and June 30, 2002, respectively.

(2) Data reflects the operations of the Jonah assets acquired on September 30, 2001.

(3) Data reflects the operations of the ARCO assets acquired on July 20, 2000.

(4) Per Unit calculation includes 3,700,000 Units issued in 2000, 7,750,000 Units issued in 2001, 13,359,597 Units issued in 2002 and 9,188,957 Units issued in 2003, net of retirement of Class B Units of 3,916,547. No Units were issued in 2004.

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

The following information is intended to provide investors with an increased understanding of our 2004, 2003 and 2002 consolidated financial statements and our accompanying notes listed in the Index to Consolidated Financial Statements on page F-1 of this Report. Our discussion and analysis includes the following:

- Overview of Business and 2004 Results.

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

- Results of Operations – Discusses material period-to-period variances in the consolidated statements of income.

- Financial Condition and Liquidity – Analyzes cash flows and financial position.

- Other Considerations – Addresses trends, future plans and contingencies that are reasonably likely to materially affect future liquidity or earnings.

Overview of Business and 2004 Results

TEPPCO Partners, L.P., a Delaware limited partnership, is a publicly traded master limited partnership formed in March 1990. See Items 1 and 2. Business and Properties – General. We operate and report in three business segments. Our Downstream Segment owns, operates or has investments in properties located in 14 states, transports, stores and provides terminal services for petroleum products, transports LPGs in the Mont Belvieu area, transports petrochemicals in southeast Texas and provides other ancillary services. Our Upstream Segment gathers, transports, markets and stores crude oil and distributes lubrication oils and specialty chemicals in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Our Midstream Segment gathers natural gas in the Green River Basin in southwestern Wyoming and in the San Juan Basin in northwestern New Mexico and southwestern Colorado, transports NGLs from southeastern New Mexico, East Texas and West Texas to Mont Belvieu, Texas, and fractionates NGLs at two facilities in Colorado. We earn revenues and income and generate cash by charging our customers a fee for the transportation, storage, gathering, terminaling, fractionation and other services we provide. In our Upstream Segment, we seek to maintain a balanced marketing position until we make physical delivery of the crude oil, thereby minimizing or eliminating our exposure to price fluctuations occurring after the initial purchase.

We are subject to economic and other factors that affect our industry. The demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products is dependent upon the price of crude oil and the products produced from the refining of crude oil; and the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled. We are also subject to regulatory factors such as the amounts we are allowed to charge our customers for the services we provide on our regulated pipeline systems.

Certain factors are inherent in our business segments as discussed in this Report. These include the safe, reliable and efficient operation of the pipelines and facilities that we own or operate while meeting increased regulations that govern the operation of our assets and the costs associated with such regulations. We are also focused on our continued growth through expansion of the assets that we own and through the acquisition of assets that complement our current operations.

Our 2004 results illustrate the strength and diversity of our asset portfolio. In 2004, solid operating performance across all of our business segments contributed to a strong year for volumes, net income and earnings before interest, taxes, depreciation and amortization. Our net income for the year ended December 31, 2004, was $142.3 million, compared with $125.8 million for the year ended December 31, 2003. We raised our annual distribution to our unitholders by $0.05 per Unit to an annualized rate of $2.65 per Unit at year end, continuing our twelve year track record of distribution increases. Distributions have increased approximately 35% over the past five years.

Our Downstream Segment had increased revenues from our refined products business and the recognition of $4.1 million of deferred revenue, despite the impact of challenging market conditions for both our refined products and LPGs movements. We have continued to utilize Centennial's capacity in a manner that has provided additional delivery capability for our customers. Centennial has provided additional capacity through our lease agreement, enabling us to transport additional refined product volumes in 2004. During the third quarter of 2004, Centennial was able to transport jet fuel for the first time. MB Storage also continued its solid performance, in part due to storage and pipeline assets acquired in April 2004. These increases were partially offset by higher pipeline integrity expenses of $6.2 million and an asset impairment charge of $4.4 million related to a marine facility in Beaumont, Texas.

Our Upstream Segment had a strong year, with increased transportation volumes and strong margins in our gathering and marketing business. Transportation volumes on our South Texas system were higher than the prior year, primarily as a result of our November 2003 acquisition of the Genesis assets. We also had a record year for gallons delivered by LSI as a result of acquisitions of lubrication oil distributors in December 2003 and August 2004. These increases were partially offset by increased pipeline integrity expenses of $3.9 million. Seaway had an outstanding year as well, with significant increases in long-haul movements of crude oil.

Our Midstream Segment benefited from increased volumes on Jonah, resulting from our recent Phase III expansion, partially offset by the impact of reduced volumes on Val Verde primarily due to the natural decline of CBM production and slower than anticipated completion and connection of new wells. Our Midstream Segment was impacted by higher operating fuel and power costs, which increased $2.2 million from 2003 primarily due to higher variable power rates and increased NGL volumes transported during times of peak power rates.

We ended 2004 in a solid financial position. Our operating costs overall were higher than expected, largely as a result of pipeline integrity expenses in our Downstream and Upstream Segments. The goal of our on-going pipeline integrity program is to maintain the long-term reliability and safety of our pipeline systems, while minimizing the impact to our customers. Our operating costs were also impacted by increased consulting and contract services of $3.2 million related to compliance with the Sarbanes-Oxley Act of 2002. During the year, we spent $104.4 million on revenue generating capital projects, which we believe will provide earnings, cash flow and growth opportunities. We amended our revolving credit facility in October 2004 to (i) increase the facility size from $550.0 million to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing.

We continued building a base for long-term growth by enhancing existing systems and pursuing new business opportunities. We increased throughput on our pipeline systems, constructed new pipeline and gathering systems, and expanded and upgraded our existing infrastructure. Among the highlights of 2004:

- During the fourth quarter of 2004, we completed a Phase II project to further extend beyond Coshocton, Ohio, our delivery capacity of LPGs to the Northeast by 8,000 to 10,000 barrels per day. The Phase II expansion included the construction of three pump stations between Coshocton and Greensburg, Pennsylvania, and two stations from Greensburg to Watkins Glen, New York. Additional work on the

pipeline segment between Greensburg and Philadelphia, Pennsylvania, to increase delivery rates to the Philadelphia area has been completed. Improvements were also completed during the fourth quarter of 2004 at our Dubois, Pennsylvania, terminal, and additional improvements are expected to be completed during the first quarter of 2005 at our Eagle, Pennsylvania, terminal.
- MB Storage acquired salt dome storage and LPGs pipeline assets in Mont Belvieu, Texas, that will enable future expansion and provide a broader platform for growth.
- We are in the process of constructing a new refined products truck loading terminal in Bossier City, Louisiana, to provide the Shreveport, Louisiana, and East Texas markets with access to Gulf Coast sourced gasoline and diesel fuel. This terminal is scheduled to be completed in the first quarter of 2005.
- We began an expansion project to increase delivery capacity of gasoline and diesel fuel to the Indianapolis, Indiana, and Chicago, Illinois market areas.
- We are in the process of integrating a strategic 58-mile pipeline segment from Houston, Texas, to Katy, Texas, to facilitate Seaway’s connectivity to Gulf of Mexico production and our South Texas system.
- In 2004, we completed the integration of the Genesis assets into our South Texas system. The $21.0 million acquisition has strengthened our existing South Texas market position and improved our physical asset base.
- The Basin system, which is a part of our Upstream Segment, was expanded between Midland, Texas, and Wichita Falls, Texas, resulting in an additional capacity of ten thousand barrels per day on the system.
- Additional capacity of 100 MMcf/day by installing compression facilities on the Jonah system was completed at a cost of approximately $13.0 million. The additional capacity will enable lower operating pressures in the Jonah and Pinedale fields, allowing for improved service and increased throughput.
- We connected Val Verde to two new sources of natural gas production in southern Colorado and northwest New Mexico. Both connections will increase the utilization of the Val Verde assets by up to 150 MMcf/day.
- We inspected more than 2,000 miles of pipeline and completed rehabilitation and enhancement work on an additional 2,000 miles of pipeline as part of our integrity management program.

We remain confident that our current strategy and focus will provide continued growth in earnings and cash distributions. With respect to 2005, these opportunities include:

- Continued solid performance in our Upstream Segment, as we build on our existing asset base and concentrate on acquisitions in our core operating areas;
- Continued development of the Jonah system which serves the Jonah and Pinedale fields;
- Gathering of volumes from infill drilling of CBM by producers and new connections of conventional gas in the San Juan Basin, where our Val Verde system is located;
- Growth in our Downstream Segment, resulting from our recent capacity expansion and grass roots facility investments and growing demand for Gulf Coast sourced products.

Consistent with our business strategy, we continuously evaluate possible acquisitions of assets that would complement our current operations. Such acquisition efforts involve participation by us in processes that have been made public and involve a number of potential buyers, as well as situations in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial position, results of operations or cash flows.

General

We operate and report in three business segments:

- Downstream Segment – transportation and storage of refined products, LPGs and petrochemicals;
- Upstream Segment – gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and
- Midstream Segment – gathering of natural gas, transportation of NGLs and fractionation of NGLs.

Our reportable segments offer different products and services and are managed separately because each requires different business strategies. TEPPCO GP, our wholly owned subsidiary, acts as managing general partner of our Operating Partnerships, with a 0.001% general partner interest and manages our subsidiaries.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand in the Northeast for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports RGP from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 6. Equity Investments).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway (see Note 6. Equity Investments). Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the fractionation of NGLs in Colorado, transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of CBM and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde. DEFS manages and operates the Val Verde, Jonah and Chaparral assets for us under contractual agreements. The results of operations of the acquisitions are included in our consolidated financial statements in periods subsequent to their respective acquisition dates (see Note 5. Acquisitions and Dispositions).

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Although we believe that these estimates are reasonable, actual results could differ from these estimates. Significant accounting policies that we employ are presented in the notes to the consolidated financial statements (see Note 2. Summary of Significant Accounting Policies).

Critical accounting policies are those that are most important to the portrayal of our financial position and results of operations. These policies require management's most difficult, subjective or complex judgments, often employing the use of estimates about the effect of matters that are inherently uncertain. Our most critical accounting policies pertain to revenue and expense accruals, environmental costs, property, plant and equipment and goodwill and intangible assets.

Revenue and Expense Accruals

We routinely make accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third party information and reconciling our records with those of third parties. The delayed information from third parties includes, among other things, actual volumes of crude oil purchased, transported or sold, adjustments to inventory and invoices for purchases and other operating expenses.

We make accruals to reflect estimates for these items based on our internal records and information from third parties. Most of the estimated accruals are reversed in the following month when actual information is received from third parties and our internal records have been reconciled.

The most difficult accruals to estimate are power costs, property taxes and crude oil margins. Power cost accruals generally involve a two to three month estimate, and the amount varies primarily for actual power usage. Power costs are dependent upon the actual volumes transported through our pipeline systems and the various power rates charged by numerous power companies along the pipeline system. Peak demand rates, which are difficult to predict, drive the variability of the power costs. For the year ended December 31, 2004, approximately 11% of our power costs are recorded using estimates. A variance of 10% in our aggregate estimate for power costs would have an approximate $0.5 million impact on annual earnings. Property tax accruals involve significant tax rate estimates among numerous jurisdictions. Actual property taxes are often not known until the tax bill is settled in subsequent periods, and the tax amount can vary for tax rate changes and changes in tax methods or elections. A variance of 10% in our aggregate estimate for property taxes could have up to an approximate $1.2 million impact on annual earnings. Crude oil margin estimates are based upon an average of the past twelve months of crude oil marketing volumes, factoring in current market events, and prices of crude oil. We use an average of prices that were in effect during the applicable month to determine the expected revenue amount, and we determine the margin by evaluating the actual margins of the prior twelve months. As of December 31, 2004, approximately 10% of our annual crude oil margin is recorded using estimates. A variance from this estimate of 10% would impact the respective line items by approximately $1.0 million on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate. Each of these accruals requires management's subjective judgments, requiring estimates regarding the effects of items that are inherently uncertain.

Environmental Costs

At December 31, 2004, we have accrued a liability of $5.0 million for our estimate of the future payments we expect to pay for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations. A variance of 10% in our aggregate estimate for environmental costs would have an approximate $0.5 million impact on annual earnings. For information concerning environmental regulation and environmental costs and contingencies, see Items 1 and 2. Business and Properties – Environmental Matters.

Property, Plant and Equipment

We regularly review long-lived assets for impairment in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to future net cash flows expected to be generated by the asset. Estimates of future net cash flows include anticipated future revenues, expected future operating costs and other estimates. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

Goodwill and Intangible Assets

Goodwill and intangible assets represent the excess of consideration paid over the fair value of tangible net assets acquired. Certain assumptions and estimates are employed in determining the fair value of assets acquired including goodwill and other intangible assets as well as determining the allocation of goodwill to the appropriate reporting unit. In addition, we assess the recoverability of these intangibles by determining whether the amortization of these intangibles over their remaining useful lives can be recovered through undiscounted future net cash flows of the acquired operations. The amount of impairment, if any, is measured by the amount by which the carrying amounts exceed the projected discounted future operating cash flows. During 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinues the amortization of goodwill and intangible assets that have indefinite lives and requires an annual test of impairment based on a comparison of fair value to carrying values. The evaluation of impairment under SFAS 142 requires the use of projections, estimates and assumptions as to the future performance of the operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Based on our assessment, we do not believe our goodwill is impaired, and we have not recorded a charge from the adoption of SFAS 142 (see Note 3. Goodwill and Other Intangible Assets). At December 31, 2004, the recorded value of goodwill and equity method goodwill was $16.9 million and $25.5 million, respectively. In addition, we have $33.4 million of excess investment in our equity investment in Centennial, which is being accounted for as an intangible asset with an indefinite life.

At December 31, 2004, we have $371.6 million of intangible assets related to natural gas transportation contracts which were recorded as part of our acquisitions of Jonah on September 30, 2001, and Val Verde on June 30, 2002 (see Note 5. Acquisitions and Dispositions). The value assigned to the natural gas transportation contracts required management to make estimates regarding the fair value of the assets acquired. In connection with the acquisition of Jonah, we assumed contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming. We assigned $222.8 million of the purchase price to these production contracts based upon a fair value appraisal at the time of the acquisition. In connection with the acquisition of Val Verde, we assumed fixed-term gas transportation contracts with customers in the San Juan Basin in New Mexico and Colorado. We assigned $239.6 million of the purchase price to these fixed term contracts based upon a fair value appraisal at the time of the acquisition. The value assigned to intangible assets is amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. The amortization of the Jonah and Val Verde systems are expected to average approximately 35 years and 30 years, respectively. On a quarterly basis, we update throughput estimates and evaluate the remaining expected useful life of the contract assets based upon the best available information. A variance of 10% in our aggregate production estimate for the Jonah and Val Verde systems would have an approximate $2.3 million impact on annual earnings. Changes in the estimated remaining production will impact the timing of amortization expense reported for future periods.

Results of Operations

The following table summarizes financial information by business segment for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31, 2004	2003	2002
Operating revenues:			
Downstream Segment	$ 279,400	$ 266,427	$ 243,538
Upstream Segment	5,475,995	3,806,215	2,861,700
Midstream Segment	206,004	185,105	138,922
Intercompany eliminations	(3,207)	(1,915)	(1,997)
Total operating revenues	5,958,192	4,255,832	3,242,163
Operating income:			
Downstream Segment	71,263	83,704	83,098
Upstream Segment	32,265	28,416	26,408
Midstream Segment	83,605	80,288	60,741
Total operating income	187,133	192,408	170,247
Earnings before interest:			
Downstream Segment	68,648	79,844	77,115
Upstream Segment	62,054	49,671	46,735
Midstream Segment	83,732	80,577	61,010
Intercompany eliminations	—	(73)	(806)
Total earnings before interest	214,434	210,019	184,054

Interest expense	(76,280)	(89,540)	(70,537)
Interest capitalized	4,227	5,290	4,345
Net income	$ 142,381	$ 125,769	$ 117,862

Below is a detailed analysis of the results of operations, including reasons for changes in results, by each of our operating segments.

Downstream Segment

The following table provides financial information for the Downstream Segment for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,			Increase (Decrease)	
	2004	2003	2002	2004	2003
Transportation – Refined products	$ 148,166	$ 138,926	$ 123,476	$ 9,240	$ 15,450
Transportation – LPGs	87,050	91,787	74,577	(4,737)	17,210
Mont Belvieu operations	—	—	15,238	—	(15,238)
Other	44,184	35,714	30,247	8,470	5,467
Total operating revenues	279,400	266,427	243,538	12,973	22,889
Operating, general and administrative	124,905	113,389	90,034	11,516	23,355
Operating fuel and power	31,706	28,806	28,998	2,900	(192)
Depreciation and amortization	43,135	31,620	30,116	11,515	1,504
Taxes – other than income taxes	8,917	8,908	11,292	9	(2,384)
Gains on sales of assets	(526)	—	—	(526)	—
Total costs and expenses	208,137	182,723	160,440	25,414	22,283
Operating income	71,263	83,704	83,098	(12,441)	606
Equity losses	(3,402)	(4,086)	(6,815)	684	2,729
Other income – net	787	226	832	561	(606)
Earnings before interest	$ 68,648	$ 79,844	$ 77,115	$ (11,196)	$ 2,729

The following table presents volumes delivered in barrels and average tariff per barrel for the years ended December 31, 2004, 2003 and 2002 (in thousands, except tariff information):

	Years Ended December 31,			Percentage Increase (Decrease)	
	2004	2003	2002	2004	2003
Volumes Delivered:					
Refined products	152,437	154,061	138,164	(1)%	12%
LPGs	43,982	42,543	40,490	3%	5%
Total	196,419	196,604	178,654	—	10%
Average Tariff per Barrel:					
Refined products	$ 0.97	$ 0.90	$ 0.89	8%	1%
LPGs	1.98	2.16	1.84	(8)%	17%
Average system tariff per barrel	$ 1.20	$ 1.17	$ 1.11	3%	5%

The Downstream Segment is dependent in large part on the demand for refined petroleum products in the markets served by its pipelines. Reductions in that demand adversely affect the pipeline business of the Downstream Segment. Market demand varies based upon the different end uses of the refined products shipped in the Downstream Segment. Demand for gasoline, which in recent years has accounted for approximately one-half of the Downstream Segment’s refined products transportation revenues, depends upon price, prevailing economic conditions and demographic changes in the markets served in the Downstream Segment. Demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities, which use distillates as a substitute for natural gas when the price of natural gas is high, and usage for agricultural operations, which is affected by weather conditions, government policy and crop prices. Demand for jet fuel, which in recent years has accounted for approximately one-quarter of the Downstream Segment’s refined products revenues, depends on prevailing economic conditions and military usage. Propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred in the past and will likely continue to occur in the future.

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Revenues from refined products transportation increased $9.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Refined products transportation revenues increased primarily due to higher market-based tariff rates which went into effect in July 2003 and May 2004 and a shift in the distribution of product moved by us to favor longer haul, higher tariff movements. These changes resulted in a 5% increase in the refined products average rate per barrel from the prior year and offset the effect of a 1% decrease in refined products delivery volumes. In February 2003, we entered into a lease agreement with Centennial that increased our flexibility to deliver refined products to our market areas. Volumes transported on Centennial increased due to increased demand and market share for products supplied from the U.S. Gulf Coast into Midwest markets. Centennial has provided our system with additional pipeline capacity for products originating in the U.S. Gulf Coast area. Prior to the construction of Centennial, deliveries on our pipeline system were limited by our pipeline capacity, and transportation services for our customers were allocated in accordance with a proration policy. With this incremental pipeline capacity, our previously constrained system has expanded deliveries in markets both south and north of Creal Springs.

Refined products transportation revenues also increased due to the recognition of $4.1 million of deferred revenue related to the expiration of two customer transportation agreements. Under some of our transportation agreements with customers, the contracts specify minimum payments for transportation services. If the transportation services paid for are not used, the unused transportation service is recorded as deferred revenue. The contracts generally specify a subsequent period of time in which the customer can transport excess products to recover the amount recorded as deferred revenue.

During the third quarter of 2004, the time limit under two transportation agreements expired without the customers recovering the unused transportation services. As a result, we recognized the deferred revenue as refined products revenue in the current period. This additional revenue increased the refined products average tariff for the year ended December 31, 2004, by $0.02 per barrel, or 2%.

Revenues from LPGs transportation decreased $4.7 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to lower deliveries of propane in the upper Midwest and Northeast market areas attributable to warmer weather during the first and fourth quarters of 2004. Additionally, in late February 2004, the Mont Belvieu propane price spiked, which resulted in TEPPCO sourced propane being less competitive than propane from other source points. Also contributing to the decrease were less favorable price differentials between Mont Belvieu and other supply centers during the second and third quarters of 2004. High propane prices in 2004 also reduced the summer and early fall fill of consumer storage of propane during 2004. These decreases were partially offset by increased deliveries of isobutane to Chicago area refineries and increased short-haul propane deliveries to U.S. Gulf Coast petrochemical customers. The LPGs average rate per barrel decreased 8% from the prior year period primarily as a result of increased short-haul deliveries during 2004.

Other operating revenues increased $8.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to higher propane inventory fees, higher margins on product inventory sales, higher revenue from our Providence, Rhode Island import facility and higher refined products tender deduction, loading and custody transfer revenues.

Costs and expenses increased $25.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to increased operating, general and administrative expenses, increased depreciation and amortization expense and increased operating fuel and power, partially offset by net gains on the sales of assets. Operating, general and administrative expenses increased primarily due to a $6.2 million increase in pipeline inspection and repair costs associated with our integrity management program, a $2.0 million increase in legal accruals related to the settlement of a lawsuit (see Note 16. Commitments and Contingencies), a $1.5 million increase in rental expense from the Centennial pipeline capacity lease agreement that we entered into in February 2003, a $1.3 million increase in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002 and a $1.1 million increase in costs related to unsuccessful acquisition evaluations. These increases were partially offset by $0.8 million of lower expenses in the 2004 period associated with the write-off of receivables related to customer bankruptcies and non-payments in 2003. Depreciation expense increased from the prior year period because of a $4.4 million charge resulting from the impairment of marine assets in the Beaumont area (see Note 9. Property, Plant and Equipment). In addition, we wrote off approximately $2.1 million in assets taken out of service during the period to depreciation expense. Depreciation expense also increased approximately $5.0 million as a result of assets placed in service during 2003 and 2004, partially offset by an increase in the estimated remaining life of a section of our pipeline system in the Northeast, resulting from pipeline capital improvements made as part of our integrity management program. Operating fuel and power expense increased primarily as a result of higher power rates during the 2004 period. In addition, we recognized net gains of $0.5 million during 2004 from the sales of various assets in the Downstream Segment.

Net losses from equity investments decreased $0.7 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, as shown below (in thousands):

	Years Ended December 31, 2004	Years Ended December 31, 2003	Increase (Decrease)
Centennial	$ (11,237)	$ (11,373)	$ 136
MB Storage	7,874	7,354	520
Other	(39)	(67)	28
Total equity losses	$ (3,402)	$ (4,086)	$ 684

Equity losses in Centennial for the year ended December 31, 2004, compared with the year ended December 31, 2003, decreased $0.1 million, primarily due to increased transportation revenues and volumes and lower operating expenses. During 2003, we acquired an additional 16.7% interest in Centennial on February 10, 2003, bringing TE Products' ownership interest to 50%. Included in the equity loss for the year ended December 31, 2004, is $1.2 million of equity income relating to the settlement of certain transmix matters recognized in previous periods.

Equity earnings from our 50% ownership interest in MB Storage increased $0.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. In April 2004, MB Storage acquired storage and pipeline assets and contracts for approximately $34.0 million, of which TE Products contributed $16.5 million. The increase in equity earnings is due to increased storage revenue, shuttle revenue and rental revenue primarily from the acquired contracts and lower pipeline rehabilitation expenses on the MB Storage system, partially offset by increased amortization and depreciation expense on storage assets and contracts acquired.

Other income – net increased $0.6 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to higher interest income earned on cash investments and higher interest income earned on a capital lease.

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

Revenues from refined products transportation increased $15.5 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, due to an overall increase of 12% in the refined products volumes delivered. This increase in volumes delivered was primarily due to deliveries of products received into our pipeline from Centennial at Creal Springs, Illinois. Centennial, which began operations in April 2002, has provided our system with additional pipeline capacity for products originating in the U.S. Gulf Coast area. In February 2003, we entered into a lease agreement with Centennial that increased our capacity to deliver refined products to our market areas. Prior to the lease agreement with Centennial, deliveries on our pipeline system were based upon a proration policy, which limited customer transportation. During 2003, with the expanded capacity through our lease agreement with Centennial, our pipeline system was not prorated during portions of 2003 and was better able to serve markets which increased transportation on our system. In addition, in December 2002, we raised the operating pressure of our Chicago lateral pipeline, which resulted in an increase in capacity for deliveries into the Indianapolis and Chicago markets. With this incremental pipeline capacity, our previously constrained system has expanded deliveries in markets both south and north of Creal Springs. Volume increases were due to increased demand and market share for products supplied from the U.S. Gulf Coast into Midwest markets. The refined products average rate per barrel increased 1% from the prior year period primarily due to higher market-based tariff rates which went into effect in July 2003, partially offset by the impact of the Midwest origin point for barrels received from Centennial, which resulted in an increase in short-haul barrels transported on our system.

Revenues from LPGs transportation increased $17.2 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to increased deliveries of propane in the upper Midwest and Northeast market areas attributable to colder than normal weather during the first quarter of 2003 and due to low inventories at competing supply locations during the second and third quarters of 2003. The U.S. Gulf Coast had higher propane inventory during 2003 as compared to the previous year because of higher than normal foreign propane imports at Mont Belvieu, which resulted in a lower propane price in this market area. This lower price contributed to increased transportation deliveries to the mid-continent market areas. Additional pipeline capacity for expanded propane movements was available due to a shift of refined product volumes to Centennial. Butane deliveries also increased due to the increased demand by refineries for normal butane for use in gasoline blending and increased isobutane deliveries to Chicago area refineries. The LPGs average rate per barrel increased 17% from the prior year period as a result of an increased percentage of long-haul deliveries during the year ended December 31, 2003, and an increase in LPG tariff rates, which went into effect in July 2003.

Effective January 1, 2003, TE Products' 50% ownership interest in MB Storage is accounted for as an equity investment as a result of the formation of MB Storage. Revenues and expenses related to Mont Belvieu operations are now recorded within equity earnings. See discussion regarding changes in equity earnings/losses below.

Other operating revenues increased $5.4 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to the addition of the northern portion of the Dean Pipeline to the Downstream Segment in January 2003, which increased other operating revenues by $4.5 million as the pipeline began transporting RGP in January 2003. The increase was also due to higher propane deliveries at our Providence, Rhode Island import facility and higher refined product loading fees. These increases were partially offset by lower revenues from product location exchanges which are used to position product in the Midwest market area and lower volume of product inventory sales.

Costs and expenses increased $22.3 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, due to increased operating, general and administrative expenses and increased depreciation and amortization expense, partially offset by decreased taxes – other than income taxes and decreased operating fuel and power. Operating, general and administrative expenses increased primarily due to higher pipeline maintenance expenses, due in part to pipeline rehabilitation expenses associated with our integrity management program, increased consulting and contract services, increased labor costs primarily due to an increase in the number of employees between years, increased insurance expense, expense from the Centennial pipeline capacity lease agreement that we entered into in 2003 and the write-off of receivables of $0.8 million related to customer bankruptcies or other customer non-payments. The addition of the northern portion of the Dean Pipeline to the Downstream Segment increased operating, general and administrative expense by $0.7 million. Depreciation expense increased from the prior year period because of assets placed in service during the year. In addition, we wrote off assets taken out of service during the period to depreciation expense, which also increased depreciation expense. These increases in depreciation expense were partially offset by lower depreciation expense from assets retired during the year, which reduced the asset base, and due to the transfer of assets to MB Storage. Taxes – other than income taxes decreased as a result of actual property taxes being lower than previously estimated and due to the transfer of assets to MB Storage. Operating fuel and power expense decreased as a result of lower power costs due to a slight decrease in the price of natural gas, partially offset by increased mainline throughput.

Net losses from equity investments decreased $2.7 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, as shown below (in thousands):

	Years Ended December 31, 2003	Years Ended December 31, 2002	Increase (Decrease)
Centennial	$ (11,373)	$ (6,716)	$ (4,657)
MB Storage	7,354	—	7,354
Other	(67)	(99)	32
Total equity losses	$ (4,086)	$ (6,815)	$ 2,729

Equity losses in Centennial for the year ended December 31, 2003, increased $4.7 million compared with the year ended December 31, 2002, due to higher operating expenses primarily as a result of a full year of operating costs in 2004, partially offset by higher transportation volumes and revenues. Centennial commenced operations in April 2002. On February 10, 2003, TE Products acquired an additional 16.7% interest in Centennial, bringing its ownership interest to 50%. In April 2003, TE Products entered into a pipeline capacity lease with Centennial for a period of five years in order to expand its capacity to deliver refined products to its market areas.

Equity earnings from our 50% ownership interest in MB Storage was $7.4 million for the year ended December 31, 2003. Amounts in the prior year period related to Mont Belvieu operations, which were recorded to revenues and costs and expenses are now being recorded within equity earnings based upon our 50% ownership interest in MB Storage, effective with its formation on January 1, 2003. If the 2002 revenues and costs and expenses from the Mont Belvieu operations had been accounted for under the same method as in 2003, equity earnings from MB Storage would have increased $0.2 million in 2003, compared with the prior year, due to increased shuttle deliveries and increased storage revenue, partially offset by increases in depreciation expense and rehabilitation expenses on MB Storage assets.

Other income – net decreased $0.6 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to lower interest income earned on cash investments.

Upstream Segment

The following table provides financial information for the Upstream Segment for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,			Increase (Decrease)	
	2004	2003	2002	2004	2003
Sales of petroleum products	$ 5,426,832	$ 3,766,651	$ 2,823,800	$ 1,660,181	$ 942,851
Transportation – Crude oil	37,177	29,057	27,414	8,120	1,643
Other	11,986	10,507	10,486	1,479	21
Total operating revenues	5,475,995	3,806,215	2,861,700	1,669,780	944,515
Purchases of petroleum products	5,370,234	3,713,122	2,774,325	1,657,112	938,797
Operating, general and administrative	51,424	50,471	43,362	953	7,109
Operating fuel and power	5,490	3,672	3,378	1,818	294
Depreciation and amortization	13,130	11,311	11,186	1,819	125
Taxes – other than income taxes	3,979	3,171	3,041	808	130
Gains on sales of assets	(527)	(3,948)	—	3,421	(3,948)
Total costs and expenses	5,443,730	3,777,799	2,835,292	1,665,931	942,507
Operating income	32,265	28,416	26,408	3,849	2,008
Equity earnings	29,383	20,949	18,795	8,434	2,154
Other income – net	406	306	1,532	100	(1,226)
Earnings before interest	$ 62,054	$ 49,671	$ 46,735	$ 12,383	$ 2,936

Information presented in the following table includes the margin of the Upstream Segment, which may be viewed as a non-GAAP (Generally Accepted Accounting Principles) financial measure under the rules of the SEC. We calculate the margin of the Upstream Segment as revenues generated from the sale of crude oil and lubrication oil, and transportation of crude oil, less the costs of purchases of crude oil and lubrication oil. We believe that margin is a more meaningful measure of financial performance than sales and purchases of crude oil and lubrication oil due to the significant fluctuations in sales and purchases caused by variations in the level of volumes marketed and prices for products marketed. Additionally, we use margin internally to evaluate the financial performance of the Upstream Segment as we believe margin is a better indicator of performance than operating income as operating, general and administrative expenses, operating fuel and power and depreciation expense are not directly related to the margin activities. Margin and volume information for the years ended December 31, 2004, 2003 and 2002 is presented below (in thousands, except per barrel and per gallon amounts):

	Years Ended December 31,			Percentage Increase (Decrease)	
	2004	2003	2002	2004	2003
Margins: (1)					
Crude oil transportation	$ 55,425	$ 45,794	$ 39,025	21%	17%
Crude oil marketing	22,468	22,017	22,914	2%	(4)%
Crude oil terminaling	9,388	9,403	10,124	—	(7)%
Lubrication oil sales	6,494	5,372	4,826	21%	11%
Total margin	$ 93,775	$ 82,586	$ 76,889	14%	7%
Total barrels:					
Crude oil transportation	101,462	95,541	82,813	6%	15%
Crude oil marketing	177,273	159,710	139,182	11%	15%
Crude oil terminaling	113,197	115,076	127,376	(2)%	(10)%
Lubrication oil volume (total gallons)	13,964	10,449	9,648	34%	8%
Margin per barrel:					
Crude oil transportation	$ 0.546	$ 0.479	$ 0.471	14%	2%
Crude oil marketing	0.127	0.138	0.165	(8)%	(16)%
Crude oil terminaling	0.083	0.082	0.080	1%	3%
Lubrication oil margin (per gallon):	$ 0.465	$ 0.514	$ 0.500	(10)%	3%

(1) Margins in this table are presented prior to the elimination of intercompany sales, revenues and purchases between TCO and TCPL.

The following table reconciles the Upstream Segment margin to operating income in the consolidated statements of income using the information presented in the tables above, in the consolidated statements of income and in the statements of income in Note 17. Segment Information (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Sales of petroleum products	$ 5,426,832	$ 3,766,651	$ 2,823,800
Transportation – Crude oil	37,177	29,057	27,414
Less: Purchases of petroleum products	(5,370,234)	(3,713,122)	(2,774,325)
Total margin	93,775	82,586	76,889
Other operating revenues	11,986	10,507	10,486
Total operating revenues	105,761	93,093	87,375
Operating, general and administrative	51,424	50,471	43,362
Operating fuel and power	5,490	3,672	3,378
Depreciation and amortization	13,130	11,311	11,186
Taxes – other than income taxes	3,979	3,171	3,041

Gains on sales of assets	(527)	(3,948)	—
Operating income	$ 32,265	$ 28,416	$ 26,408

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Our margin increased $11.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Crude oil transportation margin increased $9.6 million primarily due to an increase in transportation volumes and revenues on our South Texas system and our Red River system. Our Basin system also had increased transportation volumes and revenues primarily due to the expansion of the system between Midland, Texas, and Wichita Falls, Texas, resulting in an additional capacity of ten thousand barrels per day on the system, and movements of barrels on higher tariff segments. During the fourth quarter of 2003, we completed the purchase of crude supply and transportation assets (Genesis), which have been integrated into our South Texas system (see Note 5. Acquisitions and Dispositions). Lubrication oil sales margin increased $1.1 million due to increased sales of chemical volumes and increased volumes related to the acquisitions of lubrication oil distributors in Abilene, Texas, in December 2003 and in Casper, Wyoming, in August 2004. Crude oil marketing margin increased $0.5 million as a result of increased volumes marketed, partially offset by an unfavorable invoicing settlement on a marketing contract in the first quarter of 2003, which reduced the marketing margin in 2003, and increased transportation costs. Crude oil terminaling margin remained unchanged as a result of higher pumpover volumes at Cushing, Oklahoma, offset by lower pumpover volumes at Midland, Texas.

Other operating revenues of the Upstream Segment increased $1.5 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to a $1.4 million favorable settlement of inventory imbalances, and higher revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $5.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to increased operating fuel and power, increased depreciation and amortization expense, increased operating, general and administrative expenses and increased taxes – other than income taxes. Operating fuel and power increased $1.8 million primarily as a result of the acquisition of the Genesis assets and higher volumes in 2004. Depreciation and amortization expense increased $1.8 million primarily due to the assets acquired from Genesis. Operating, general and administrative expenses increased $1.0 million from the prior year primarily due to a $3.9 million increase in pipeline inspection and repair costs associated with our integrity management program, a $2.0 million increase in expenses related to the Genesis acquisition, a $1.4 million increase in labor and benefits expense related to incentive compensation plans and an increase in the number of employees between periods, a $0.7 million increase in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002 and a $0.6

million increase in rental expense due to our pipeline lease at Freeport, Texas, with Seaway. These increases were partially offset by $3.8 million of higher environmental assessment and remediation costs in 2003, $1.7 million of expense in 2003 from the net settlement of crude oil imbalances with customers, $1.5 million of higher legal costs in 2003 related to the litigation and settlement with D.R.D. Environmental Services, Inc. ("D.R.D.") and $0.5 million of lower expenses in 2004 from the sale of the Rancho assets in 2003. Taxes – other than income taxes increased $0.8 million due to increases in property tax accruals.

In June 2003, we recorded a net gain of $3.9 million, included in the gain on sale of assets in our consolidated statements of income, on the sale of certain of the assets of the Rancho Pipeline. During the year ended December 31, 2004, we recorded net gains of $0.5 million, included in the gains on sales of assets in our consolidated statements of income, primarily related to the sale of our remaining interest in the original Rancho Pipeline system (see Note 5. Acquisitions and Dispositions).

Equity earnings from our investment in Seaway increased $8.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to higher transportation volumes, gains on crude oil inventory sales, a settlement with a former owner of Seaway's crude oil assets regarding inventory imbalances that were not acquired by us and lower operating, general and administrative expenses.

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

Our margin increased $5.7 million for the year ended December 31, 2003, compared with the year ended December 31, 2002. Crude oil transportation margin increased $6.8 million primarily due to increased revenues on our Red River, Basin, South Texas and West Texas systems resulting from a 15% increase in transportation volumes on these systems partially due to the acquisition of the Genesis assets. During the fourth quarter of 2003, we completed the purchase of crude supply and transportation assets (Genesis), which was integrated into our South Texas system. The acquisition of the Genesis assets increased our transportation and marketing margins by approximately $1.2 million and the barrels transported and marketed by approximately 1.6 million barrels during 2003. Lubrication oil sales margin increased $0.5 million due to increased sales of chemical volumes, higher margins on lubrication sales and increased volumes related to the acquisition of a lubrication oil distributor in Abilene, Texas, in December 2003. Crude oil marketing margin decreased $0.9 million primarily due to an invoicing settlement on a marketing contract in the first quarter of 2003, partially offset by increased volumes marketed, renegotiated supply contracts, lower trucking expenses and more favorable crude oil price differentials. Crude oil terminaling margin decreased $0.7 million as a result of a 10% decrease in volumes at Midland, Texas, and Cushing, Oklahoma.

Costs and expenses, excluding expenses associated with purchases of crude oil and lubrication oil, increased $7.6 million for the year ended December 31, 2003, compared with the year ended December 31, 2002. Operating, general and administrative expenses increased $7.1 million from the prior year period. The increase includes a $2.4 million increase in environmental assessment and remediation costs in 2003, higher legal costs related to the litigation and settlement with D.R.D. and other legal costs (see Note 16. Commitments and Contingencies), $1.7 million of expense from the net settlement of crude oil imbalances with customers, higher pipeline rehabilitation expenses associated with our integrity management program and increased labor costs due to an increase in the number of employees between periods, partially offset by lower general and administrative supplies expenses during the period. In addition, the acquisition of the Genesis assets and integration into our South Texas system during the fourth quarter increased operating, general and administrative expenses by approximately $0.5 million. Operating fuel and power increased $0.3 million due to higher power costs and higher volumes in 2003. Depreciation and amortization expense increased $0.1 million due to assets placed in service in 2002 and 2003 and due to asset retirements. Taxes – other than income taxes increased $0.1 million due to slight increases in property tax accruals.

Equity earnings from our investment in Seaway increased $2.2 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, due to a favorable crude oil imbalance settlement, a gain on the sale of inventory, lower general and administrative expenses and higher long-haul transportation volumes, partially offset by our portion of equity earnings which decreased from 80% to 60% on a pro-rated basis in 2002 (averaging approximately 67% for the year ended December 31, 2002), to 60% in 2003.

In June 2003, we recorded a net gain of $3.9 million, included in the gain on sale of assets in our consolidated statements of income, on the sale of certain of the assets of the Rancho Pipeline. In connection with our acquisition of crude oil assets in 2000, we acquired an approximate 23.5% undivided joint interest in the Rancho Pipeline, which was a crude oil pipeline system from West Texas to Houston. In March 2003, the Rancho Pipeline ceased operations, and segments of the pipeline were sold to certain of the current owners that previously held undivided interests in the pipeline. We acquired 241 miles of the pipeline in exchange for cash of $5.5 million and our interests in other portions of the Rancho Pipeline. We sold 183 miles of the segment we acquired to other entities for cash and assets valued at approximately $8.5 million.

Other income – net decreased $1.2 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to lower interest income received on intercompany borrowings.

Midstream Segment

The following table provides financial information for the Midstream Segment for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,			Increase (Decrease)	
	2004	2003	2002	2004	2003
Sales of petroleum products	$ 7,295	$ —	$ —	$ 7,295	$ —
Gathering – Natural gas	140,122	135,144	90,053	4,978	45,091
Transportation – NGLs	41,204	39,837	38,870	1,367	967
Other	17,383	10,124	9,999	7,259	125
Total operating revenues	206,004	185,105	138,922	20,899	46,183
Purchases of petroleum products	5,944	—	—	5,944	—
Operating, general and administrative	47,053	37,469	25,357	9,584	12,112
Operating fuel and power	8,208	6,033	4,438	2,175	1,595
Depreciation and amortization	56,629	57,797	44,730	(1,168)	13,067
Taxes – other than income taxes	4,565	3,518	3,656	1,047	(138)
Total costs and expenses	122,399	104,817	78,181	17,582	26,636
Operating income	83,605	80,288	60,741	3,317	19,547
Other income – net	127	289	269	(162)	20
Earnings before interest	$ 83,732	$ 80,577	$ 61,010	$ 3,155	$ 19,567

The following table presents volume and average rate information for the years ended December 31, 2004, 2003 and 2002 (in thousands, except average fee and average rate amounts):

	Years Ended December 31,			Percentage Increase (Decrease)	
	2004	2003	2002	2004	2003
Gathering – Natural Gas – Jonah:					
Million cubic feet	354,546	302,951	248,360	17%	22%
Million British thermal units (“MMBtu”)	392,154	336,032	275,831	17%	22%
Average fee per MMBtu	$ 0.194	$ 0.193	$ 0.182	1%	6%
Gathering – Natural Gas – Val Verde:					
Million cubic feet	144,539	158,286	92,336	(9)%	71%
MMBtu	122,706	133,094	77,831	(8)%	71%
Average fee per MMBtu	$ 0.523	$ 0.529	$ 0.515	(1)%	3%
Transportation – NGLs:					
Thousand barrels	59,549	57,902	53,980	3%	7%
Average rate per barrel	$ 0.692	$ 0.688	$ 0.720	1%	(4)%
Fractionation – NGLs:					
Thousand barrels	4,149	4,131	4,072	—	1%
Average rate per barrel	$ 1.797	$ 1.804	$ 1.824	—	(1)%
Sales – Condensate:					
Thousand barrels	84.4	63.3	80.0	33%	(21)%
Average rate per barrel	$ 37.99	$ 30.25	$ 25.39	26%	19%

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Revenues from the gathering of natural gas increased $5.0 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Natural gas gathering revenues from the Jonah system increased $11.3 million and volumes gathered increased 51.6 Bcf for the year ended December 31, 2004, due to the expansion of the Jonah system during 2003. The Phase III expansion was substantially completed during the fourth quarter of 2003 and increased system capacity from 880 MMcf/day to 1,180 MMcf/day. The increase in Jonah's revenues was also partially due to higher gathering rates realized due to lower system pressures resulting from the increased capacity provided by the Phase III expansion. Natural gas gathering revenues from the Val Verde system decreased $6.3 million and volumes gathered decreased 13.7 Bcf for the year ended December 31, 2004, primarily due to the natural decline of CBM production and slower than anticipated completion and connection of infill wells, partially offset by increased volumes from two new connections made to the Val Verde system in May and December 2004. Val Verde's average natural gas gathering rate per MMcf decreased due to contracts entered into relating to the new connections, which have lower rates than the existing Val Verde system's average rates.

Jonah's Pioneer gas processing plant was completed during the first quarter of 2004, as a part of the Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allow the producers to elect annually whether to be charged under a fee-based arrangement or a fee plus keep-whole arrangement. Under the fee-based election, Jonah receives a fee for its processing services. Under the fee plus keep-whole election, Jonah receives a lower fee for its processing services, retains and sells the NGLs extracted during the process and delivers to the producers residue gas equivalent in energy to the natural gas received from the producers. Jonah purchases gas from an affiliate of DEFS to replace the equivalent energy removed in the liquids. Jonah sells the NGLs it retains to an affiliate of DEFS. For the year ended December 31, 2004, the sales and purchases under the fee arrangements at the Pioneer plant resulted in a margin (sales of petroleum products less purchases of petroleum products) of $1.4 million.

Revenues from the transportation of NGLs increased $1.4 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to increases in volumes transported on the

Chaparral and Panola Pipelines, partially offset by decreased volumes on the Dean and Wilcox Pipelines. Higher average rates per barrel on volumes transported on the Panola and Wilcox Pipelines were offset by lower average rates per barrel on volumes transported on the Chaparral and Dean Pipelines.

Other operating revenues increased $7.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003. Processing fee revenues increased $2.8 million as a result of Jonah's Pioneer processing plant, which was constructed as part of the Phase III expansion and placed in service in January 2004. Jonah's other operating revenues also increased $0.9 million primarily due to higher condensate sales. Other operating revenues on Chaparral increased $1.9 million due to the recognition of deferred revenue related to an inventory settlement. Val Verde's operating revenues increased $1.6 million due to revenues generated as a result of contractual producer minimum fuel levels exceeding actual operating fuel usage during the year ended December 31, 2004. Val Verde retains a portion of its producers' gas to compensate for fuel used in operations. The actual usage of gas can differ from the amount contractually retained from producers. Value retained from producers or sales generated as a result of efficient fuel usage is recognized as other operating revenues.

Costs and expenses (excluding purchases of petroleum products) increased $11.7 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to increases in operating, general and administrative expense, operating fuel and power and taxes – other than income taxes, partially offset by a decrease in depreciation and amortization expense. Operating, general and administrative expense increased due to a $3.8 million increase in gas settlement expenses, a $3.0 million increase in general and administrative labor expense, a $1.3 million increase in consulting and contract services related to compliance with the Sarbanes-Oxley Act of 2002, a $0.9 million increase related to our integrity management program and a $0.9 million increase related to Jonah's processing plant which began operations in 2004. These increases are partially offset by a $0.6 million decrease in expense related to the sale of our Enron Corp. receivable, which had been fully reserved in 2001, and a $0.4 million decrease in maintenance expenditures at Val Verde. Operating fuel and power increased $2.2 million, primarily due to higher variable power rates and increased NGL volumes transported during times of peak variable power rates. Depreciation expense increased $3.5 million, primarily as a result of assets placed in service in 2003 related to the expansion of the Jonah system and additional well connections on the Val Verde system in 2004. Taxes – other than income taxes increased $1.0 million as a result of higher property balances. Amortization expense decreased $4.7 million primarily due to revisions to the estimated life of Jonah's intangible assets under the units-of-production method, partially offset by a $1.7 million increase as a result of higher volumes in the 2004 period. In second quarter 2003, Jonah's estimated total throughput of the system was adjusted, which resulted in an extension of the expected amortization period from 16 years to 25 years. During the fourth quarter of 2004, additional limited production forecasts were obtained from some of the producers on the Jonah system related to future expansions of the system, and as a result, we again increased our best estimate of future throughput on the Jonah system. This increase in the estimate of future throughput extended the amortization period of Jonah's natural gas gathering contracts by an estimated 10 years, increasing from approximately 25 years to approximately 35 years (see Note 3. Goodwill and Other Intangible Assets). Amortization expense on the Val Verde system decreased $2.1 million primarily due to lower volumes in the 2004 period, resulting from the natural decline in CBM production.

Other income – net decreased $0.2 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to lower interest income earned on cash investments.

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

Revenues from the gathering of natural gas increased $45.1 million for the year ended December 31, 2003, compared with the year ended December 31, 2002. Natural gas gathering revenues from the Jonah system increased $14.6 million and volumes gathered increased 54.6 Bcf for the year ended December 31, 2003, due to the expansions of the Jonah system during 2002. The first expansion, which was completed in May 2002, increased the capacity of the Jonah system by 62%, from approximately 450 MMcf/day to approximately 730 MMcf/day. In October 2002, additional expansion projects were completed, which increased the capacity of the Jonah system from 730 MMcf/day to approximately 880 MMcf/day. A Phase III expansion was substantially completed during the fourth quarter of 2003 and increased system capacity to 1,180 MMcf/day. The increase in Jonah's revenues was also partially due to an increase in the average natural gas gathering rate due to certain volume thresholds being exceeded. Natural gas gathering revenues from the Val Verde system increased $30.5 million and volumes gathered increased 65.9 Bcf for the year ended December 31, 2003, primarily due to the acquisition of the Val Verde system

on June 30, 2002. Volumes delivered for the first half of 2003 were approximately 82.0 Bcf. As Val Verde was acquired on June 30, 2002, there were no comparable volumes for the first half of 2002. Volumes delivered during the second half of 2003 as compared to the second half of 2002 declined approximately 16.0 Bcf. This decrease in volumes during the second half of 2003 was due to the natural decline of CBM production, which resulted in decreased revenues, partially offset by an increase in the average natural gas gathering rate due to annual fee escalations in gathering agreements and higher carbon dioxide treating fees as a result of increasing carbon dioxide content in the natural gas.

Revenues from the transportation of NGLs increased $1.0 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to an increase of $4.4 million related to the acquisition of Chaparral on March 1, 2002, $0.7 million due to an increase in volumes transported on Chaparral and $0.2 million due to an increase in volumes transported on the Wilcox Pipeline. This increase was partially offset by a decrease of $2.4 million due to lower transportation volumes on Panola as a result of lower NGL volumes available from the connected NGL plants and a decrease of $1.9 million on the southern portion of the Dean Pipeline due to decreased transportation volumes. Lower transportation volumes on the southern portion of the Dean Pipeline resulted from the conversion of the northern portion of the pipeline to transport RGP and subsequent classification as a part of the Downstream Segment, effective January 1, 2003. The decrease in the NGL transportation average rate per barrel resulted from a lower average rate per barrel on volumes transported on Chaparral.

Costs and expenses increased $26.6 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, due to increased depreciation and amortization expense, increased operating, general and administrative expense and increased operating fuel and power, partially offset by decreased taxes – other than income taxes. Depreciation and amortization expense increased $14.6 million due to the Chaparral and Val Verde assets acquired on March 1, 2002, and June 30, 2002, respectively, $0.3 million due to assets placed in service in 2002 related primarily to the expansions of the Jonah system and $2.0 million in amortization expense on Jonah's intangible assets under the units-of-production method, as volumes gathered increased between periods. These increases were partially offset by a decrease of $1.8 million in amortization expense on Val Verde's intangible assets under the units-of-production method as volumes gathered decreased between periods. In addition, amortization expense on Jonah decreased $2.0 million related to its intangible assets. In second quarter 2003, Jonah's estimated total throughput of the system was adjusted, which resulted in an extension of the expected amortization period from 16 years to 25 years (see Note 3. Goodwill and Other Intangible Assets). Operating, general and administrative expense increased $11.0 million from the assets acquired, and $1.1 million primarily due to higher general and administrative labor and supplies expense and increased consulting and contracting services. Operating fuel and power costs increased $0.8 million due to the assets acquired and $0.8 million due to increased volumes transported on Chaparral. Taxes – other than income taxes decreased $0.2 million due to actual property taxes being lower than previously estimated on Val Verde, Panola and the southern portion of the Dean Pipeline.

Interest Expense and Capitalized Interest

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Interest expense decreased $13.3 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to a higher percentage of variable interest rate debt during the year ended December 31, 2004, that carried a lower rate of interest as compared to fixed interest rate debt. The higher percentage of variable interest rate debt resulted from the expiration of an interest rate swap in April 2004 (see Note 4. Interest Rate Swaps). The decrease was partially offset by higher balances outstanding on our revolving credit facility in 2004.

Capitalized interest decreased $1.1 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, due to interest capitalized on lower construction work-in-progress balances in 2004.

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

Interest expense increased $19.0 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to $12.3 million of additional expense related to changes in our fair value

and cash flow hedging activities, $16.1 million of additional expense related to the issuance of our 6.125% Senior Notes in January 2003 and our 7.625% Senior Notes in February 2002 and $1.3 million of debt issuance costs written off in June 2003 related to the refinancing of our revolving credit facility. These increases were partially offset by a $10.7 million reduction in interest expense related to decreased borrowings under our revolving credit facility.

Capitalized interest increased $0.9 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, due to increased construction work-in-progress balances during 2003, partially offset by interest capitalized on our investment in Centennial during the first quarter of 2002.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At December 31, 2004, and 2003, we had working capital deficits of $37.8 million and $22.8 million, respectively. At December 31, 2004, we had approximately $132.0 million in available borrowing capacity under our revolving credit facility to cover any working capital needs. Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows (in millions):

	Years Ended December 31,		
	2004	2003	2002
Cash provided by (used in):			
Operating activities	$ 266.2	$ 239.4	$ 234.9
Investing activities	(189.2)	(185.3)	(724.7)
Financing activities	(90.1)	(55.6)	495.3

Operating Activities

Net cash from operating activities for the years ended December 31, 2004, 2003 and 2002, was comprised of the following (in millions):

	Years Ended December 31,		
	2004	2003	2002
Net income	$ 142.4	$ 125.8	$ 117.9
Depreciation and amortization	112.9	100.7	86.0

Earnings in equity investments	(26.0)	(16.9)	(12.0)
Distributions from equity investments	47.2	28.0	30.9
Gains on sales of assets	(1.1)	(3.9)	—
Non-cash portion of interest expense	(0.4)	4.8	4.9
Cash provided by (used in) working capital and other	(8.8)	0.9	7.2
Net cash from operating activities	$ 266.2	$ 239.4	$ 234.9

For a discussion of changes in earnings before interest, depreciation and amortization, equity earnings, gain on sales of assets by segment and consolidated interest expense – net, see Results of Operations for the Downstream Segment, Upstream Segment and Midstream Segment in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. Cash provided by operating activities increased $26.8 million for the year ended December 31, 2004, compared with the year ended December 31, 2003, primarily due to an increase of $19.2 million in distributions received from our equity investments in Seaway and MB Storage during the year ended December 31, 2004, and higher net income and depreciation and amortization expense in the 2004 period, partially offset by the timing of cash disbursements and cash receipts for working capital components. Cash provided by operating activities increased $4.5 million for the year ended December 31, 2003, compared with the year ended December 31, 2002, primarily due to higher net income and depreciation and amortization expense resulting from our 2002 acquisition of Val Verde, partially offset by the $3.9 million non-cash gain on the sale of assets in 2003. Distributions from equity method investments decreased from 2002 to 2003, primarily due to our sharing ratio in Seaway decreasing from 80% to 60% between years, partially offset by a distribution from MB Storage in 2003 of $5.3 million.

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and revenue generating expenditures, interest payments on our Senior Notes and revolving credit facility, distributions to our General Partner and unitholders and acquisitions of new assets or businesses. Short-term cash requirements, such as operating expenses, capital expenditures to sustain existing operations and quarterly distributions to our General Partner and unitholders, are expected to be funded through operating cash flows. Long-term cash requirements for expansion projects and acquisitions are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates and our financial condition and our credit rating at the time.

Net cash from operating activities for the years ended December 31, 2004, 2003 and 2002, included interest payments, net of amounts capitalized, of $77.5 million, $79.9 million and $48.9 million, respectively. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2005, we expect interest payments on our fixed rate Senior Notes to be approximately $78.0 million. We expect to pay our interest payments with cash flows from operating activities.

Investing Activities

Cash flows used in investing activities totaled $189.2 million for the year ended December 31, 2004, and were comprised of $164.1 million of capital expenditures, $1.5 million of cash contributions for TE Products' ownership interest in Centennial, $21.4 million of cash contributions for TE Products' ownership interest in MB Storage and $3.4 million for the acquisition of assets acquired during the year ended December 31, 2004, partially offset by $1.2 million in net cash proceeds from the sales of various assets in our Upstream and Downstream Segments. Cash flows used in investing activities totaled $185.3 million for the year ended December 31, 2003, and were comprised of $140.6 million of capital expenditures, $22.0 million for our acquisition of the Genesis assets and other assets, $20.0 million for TE Products' acquisition of an additional 16.7% interest in Centennial, $4.0 million of cash contributions for TE Products' ownership interest in Centennial and $2.5 million of cash contributions for TE Products' ownership interest in MB Storage. These uses of cash were partially offset by $3.0 million in net cash proceeds from the Rancho Pipeline transactions and $0.8 million received on matured cash investments. Cash flows used in investing activities totaled $724.7 million for the year ended December 31, 2002, and were comprised of $7.3 million for the final purchase price adjustments on the acquisition of Jonah, $133.4 million of capital expenditures, $10.9 million of cash contributions for TE Products' ownership interest in Centennial, $132.4 million for the purchase of the Chaparral NGL system on March 1, 2002, and $444.2 million for the purchase of Val Verde on June 30, 2002. These uses of cash were partially offset by $3.5 million in cash proceeds from the sale of assets.

Financing Activities

Cash flows used in financing activities totaled $90.1 million for the year ended December 31, 2004, and were comprised of $233.1 million of distributions paid to unitholders, partially offset by $143.0 million in borrowings, net of repayments, from our revolving credit facility. Cash flows used in financing activities totaled $55.6 million for the year ended December 31, 2003, and were comprised of $382.0 million in proceeds from revolving credit facilities; $198.6 million from the issuance in January 2003 of our 6.125% Senior Notes due 2013, partially offset by debt issuance costs of $3.4 million; and $287.5 million from the issuance of 9.2 million Units in April and August 2003. These sources of cash for the year ended December 31, 2003, were partially offset by $604.0 million of repayments on our revolving credit facilities, $113.8 million to repurchase and retire all of the 3.9 million outstanding Class B Units, and $202.5 million of distributions paid to unitholders. Cash flows provided by financing activities totaled $495.3 million for the year ended December 31, 2002, and were comprised of $675.0 million in proceeds from revolving credit facilities; $497.8 million from the issuance in February 2002 of our 7.625% Senior Notes due 2012, partially offset by debt issuance costs of $7.0 million; $372.5 million from the issuance of 13.4 million Units during the year ended December 31, 2002, and $7.6 million of General Partner contributions; and $44.9 million of proceeds from the termination of our interest rate swaps on our 7.625% Senior Notes due 2012. These sources of cash for the year ended December 31, 2002, were partially offset by $943.7 million of repayments on our revolving credit facilities and $151.8 million of distributions paid to unitholders.

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2004, $150.0 million was outstanding under those credit facilities. The proceeds were used to fund construction and conversion costs of its pipeline system. TE Products and Marathon have each guaranteed one-half of Centennial's debt, up to a maximum of $75.0 million each.

Universal Shelf

We have filed with the SEC a universal shelf registration statement that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof. At December 31, 2004, we have $2.0 billion available under this shelf registration, subject to customary marketing terms and conditions.

Credit Facilities and Interest Rate Swap Agreements

On April 6, 2001, we entered into a $500.0 million revolving credit facility including the issuance of letters of credit of up to $20.0 million ("Three Year Facility"). The interest rate was based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Three Year Facility contained certain restrictive financial covenant ratios. During the first quarter of 2003, we repaid $182.0 million of the outstanding balance of the Three Year Facility with proceeds from the issuance of our 6.125% Senior Notes on January 30, 2003. On June 27, 2003, we repaid the outstanding balance under the Three Year Facility with borrowings under a new credit facility, and canceled the Three Year Facility.

On June 27, 2003, we entered into a $550.0 million revolving credit facility with a three year term, including the issuance of letters of credit of up to $20.0 million ("Revolving Credit Facility"). The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Revolving Credit Facility contains certain restrictive financial covenant ratios. We borrowed $263.0 million under the Revolving Credit Facility and repaid the outstanding balance of the Three Year Facility. On October 21, 2004, we amended our Revolving Credit Facility to (i) increase the facility size to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing. On December 31, 2004, $353.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 3.0%. At December 31, 2004, we were in compliance with the covenants in this credit agreement.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. We used $182.0 million of the proceeds from the offering to reduce the outstanding principal on the Three Year Facility to $250.0 million. The balance of the net proceeds received was used for general partnership purposes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2004, we were in compliance with the covenants of these Senior Notes.

We have entered into interest rate swap agreements to hedge our exposure to cash flows and fair value changes. These agreements are more fully described in Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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

	As of December 31, 2004		
Description:	**Outstanding Principal**	**Available Borrowing Capacity**	**Maturity Date**
Revolving Credit Facility (1)	$ 353.0	$ 247.0	October 2009
6.45% Senior Notes (2)	180.0	—	January 2008
7.625% Senior Notes (2)	500.0	—	February 2012
6.125% Senior Notes (2)	200.0	—	February 2013
7.51% Senior Notes (2)	210.0	—	January 2028
Total	$ 1,443.0	$ 247.0	

(1) Our Revolving Credit Facility contains restrictive covenants that require us to maintain certain financial ratios. Under the most restrictive financial covenant, approximately $132.0 million was available to be borrowed for working capital needs at December 31, 2004. Certain of these restrictive covenants are adjusted in the event of an acquisition by us, which would permit additional borrowings under the facility.

(2) Our TE Products subsidiary entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its 7.51% Senior Notes due 2028. At December 31, 2004, the 7.51% Senior Notes include an adjustment to increase the fair value of the debt by $3.4 million related to this interest rate swap agreement. We also entered into interest rate swap agreements to hedge our exposure to changes in the fair value of our 7.625% Senior Notes due 2012. At December 31, 2004, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $36.6 million. At December 31, 2004, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.8 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

Distributions and Issuance of Additional Limited Partner Units

We paid cash distributions to our limited partners and general partner, including general partner incentive distributions, of $233.1 million ($2.6375 per Unit), $202.5 million ($2.50 per Unit) and $151.9 million ($2.35 per Unit) during each of the years ended December 31, 2004, 2003 and 2002, respectively. Additionally, on January 14, 2005, we declared a cash distribution of $0.6625 per Unit for the quarter ended December 31, 2004. The distribution of $58.7 million was paid on February 7, 2005, to unitholders of record on January 31, 2005. See Note 11. Partners' Capital and Distributions.

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO. We received approximately $0.7 million in proceeds from the offering in excess of the amount needed to repurchase and retire the Class B Units.

On August 7, 2003, we sold in an underwritten public offering 5.0 million Units at $34.68 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $166.0 million. On August 19, 2003, 162,900 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on August 7, 2003. Proceeds from the over-allotment sale, net of underwriting discount, totaled $5.4 million. Approximately $53.0 million of the proceeds were used to repay indebtedness under our revolving credit facility and $21.0 million was used to fund the acquisition of the Genesis assets (see Note 5. Acquisitions and Dispositions). The remaining amount was used primarily to fund revenue-generating and system upgrade capital expenditures and for general partnership purposes.

General Partner Interest

As of December 31, 2004 and 2003, we had deficit balances of $33.0 million and $7.2 million, respectively, in our General Partner's equity account. This negative balance does not represent an asset to us and does not represent an obligation of the General Partner to contribute cash or other property to us. The General

Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Consolidated Statements of Partners' Capital for a detail of the General Partner's equity account). For the years ended December 31, 2004 and 2003, the General Partner was allocated $41.1 million (representing 28.85%) and $34.8 million (representing 27.65%), respectively, of our net income and received $66.9 million and $54.7 million, respectively, in cash distributions.

Capital Accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our 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 accounting principles generally accepted in the United States in our financial statements. Under our Partnership Agreement, the General Partner is required to make additional capital contributions to us upon the issuance of any additional Units if necessary to maintain a Capital Account balance equal to 1.999999% of the total Capital Accounts of all partners. At December 31, 2004 and 2003, the General Partner's Capital Account balance substantially exceeded this requirement.

Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period. This is generally consistent with the manner of allocating net income under our Partnership Agreement. Net income determined under our Partnership Agreement, however, incorporates principles established for U.S. federal income tax purposes and is not comparable to net income reflected under accounting principles generally accepted in the United States in our financial statements.

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion (see Note 11. Partners' Capital and Distributions). Cash distributions in excess of net income allocations and capital contributions during the years ended December 31, 2004 and 2003, resulted in a deficit in the General Partner's equity account at December 31, 2004 and 2003. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

According to the Partnership Agreement, in the event of our dissolution, after satisfying our liabilities, our remaining assets would be divided among our limited partners and the General Partner generally in the same proportion as Available Cash but calculated on a cumulative basis over the life of the Partnership. If a deficit balance still remains in the General Partner's equity account after all allocations are made between the partners, the General Partner would not be required to make whole any such deficit.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions, for 2005 will be approximately $236.0 million (which includes $6.0 million of capitalized interest). We expect to spend approximately $168.0 million for revenue generating projects and facility improvements. Capital spending on revenue generating projects and facility improvements will include approximately $23.0 million for the expansion of our Downstream Segment facilities. We expect to spend $5.0 million to expand our Upstream Segment pipelines and facilities in West Texas and Oklahoma and approximately $140.0 million to expand our Midstream Segment assets, with further expansions on our Jonah system. We expect to spend approximately $44.0 million to sustain existing operations, including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $18.0 million to improve operational efficiencies and reduce costs among all of our business segments. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

Our debt repayment obligations consist of payments for principal and interest on (i) the TE Products $180.0 million 6.45% Senior Notes due January 15, 2008, (ii) outstanding principal amounts under the Revolving Credit Facility due in October 2009 ($353.0 million outstanding at December 31, 2004), (iii) our $500.0 million 7.625%

Senior Notes due February 15, 2012, (iv) our $200.0 million 6.125% Senior Notes due February 1, 2013, and (v) the TE Products $210.0 million 7.51% Senior Notes due January 15, 2028.

TE Products is contingently liable as guarantor for the lesser of one-half or $75.0 million principal amount (plus interest) of the borrowings of Centennial. In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the year ended December 31, 2004, TE Products exceeded the minimum throughput requirements on the lease agreement. On February 10, 2003, TE Products acquired an additional 16.7% ownership interest in Centennial, bringing its ownership percentage to 50%.

During the years ended December 31, 2004, 2003 and 2002, TE Products contributed $1.5 million, $4.0 million and $10.9 million, respectively, to Centennial to cover operating needs and capital expenditures. During the years ended December 31, 2004 and 2003, TE Products contributed $21.4 million to

MB Storage, of which $16.5 million was used for its acquisition of storage and pipeline assets in April 2004, and $2.5 million, respectively, for capital expenditures. During 2005, TE Products may be required to contribute cash to Centennial to cover capital expenditures, acquisitions or other operating needs and to MB Storage to cover significant capital expenditures or additional acquisitions.

Off-Balance Sheet Arrangements

We do not rely on off-balance sheet borrowings to fund our acquisitions. We have no off-balance sheet commitments for indebtedness other than the limited guaranty of Centennial debt and leases covering assets utilized in several areas of our operations.

Contractual Obligations

The following table summarizes our debt repayment obligations and material contractual commitments as of December 31, 2004 (in millions):

	Amount of Commitment Expiration Per Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Revolving Credit Facility	$ 353.0	$ —	$ —	$ 353.0	$ —
6.45% Senior Notes due 2008 (1) (2)	180.0	—	—	180.0	—
7.625% Senior Notes due 2012 (2)	500.0	—	—	—	500.0
6.125% Senior Notes due 2013 (2)	200.0	—	—	—	200.0
7.51% Senior Notes due 2028 (1) (2)	210.0	—	—	—	210.0
Debt subtotal	1,443.0	—	—	533.0	910.0
Operating leases	79.3	18.2	28.7	12.9	19.5
Capital expenditure obligations (3)	10.0	10.0	—	—	—
Other liabilities and deferred credits (4)	4.2	—	2.4	0.4	1.4
Total	$ 1,536.5	$ 28.2	$ 31.1	$ 546.3	$ 930.9

(1) Obligations of TE Products.

(2) Our TE Products subsidiary entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its 7.51% Senior Notes due 2028. At December 31, 2004, the 7.51% Senior Notes include an adjustment to increase the fair value of the debt by $3.4 million related to this interest rate swap agreement. We also entered into interest rate swap agreements to hedge our exposure to changes in the fair value of our 7.625% Senior Notes due 2012. At December 31, 2004, the 7.625% Senior Notes include a deferred gain, net of amortization, from previous interest rate swap terminations of $36.6 million. At December 31, 2004, our 6.45% Senior Notes, our 7.625% Senior Notes and our 6.125% Senior Notes include $2.8 million of unamortized debt discounts. The fair value adjustments, the deferred gain adjustment and the unamortized debt discounts are excluded from this table.

(3) Includes accruals for costs incurred but not yet paid relating to capital projects.

(4) Excludes approximately $9.4 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

We expect to repay the long-term, senior unsecured obligations and bank debt through the issuance of additional long-term senior unsecured debt at the time the 2008, 2012, 2013 and 2028 debt matures, issuance of additional equity, with proceeds from dispositions of assets, cash flow from operations or any combination of the above items.

In addition to the items in the table above, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminaling and storage of crude oil. The majority of contractual commitments for the purchase of crude oil that are made range in term from a thirty-day evergreen to three years. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice. During the year ended December 31, 2004, crude oil purchases averaged approximately $448.0 million per month.

Sources of Future Capital

Historically, we have funded our capital commitments from operating cash flow and borrowings under bank credit facilities or bridge loans. We repaid these loans in part by the issuance of long term debt in capital markets and the public offering of Units. We expect future capital needs would be similarly funded to the extent not otherwise available from cash flow from operations.

As of December 31, 2004, we had $247.0 million in available borrowing capacity under the Revolving Credit Facility, subject to compliance with prescribed financial covenants. We expect that cash flows from operating activities will be adequate to fund cash distributions and capital additions necessary to sustain existing operations. However, future expansionary capital projects and acquisitions will require funding through borrowings under our Revolving Credit Facility or proceeds from the sale of additional debt or equity offerings, or any combination thereof.

Our senior unsecured debt is rated BBB by Standard and Poors (“S&P”) and Baa3 by Moody’s Investors Service (“Moody’s”). Both ratings are stable. A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any indebtedness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change. The senior unsecured debt of our subsidiary, TE Products, is also rated BBB by S&P and Baa3 by Moody’s. Both ratings are stable.

Other Considerations

Credit Risks

Risks of non-payment and nonperformance by customers are a major consideration in our businesses. Our credit procedures and policies do not fully eliminate customer credit risk. During the years ended December 31, 2003 and 2002, some of our customers filed for bankruptcy protection. During the years ended December 31, 2004, 2003 and 2002, we expensed approximately $0.1 million, $0.8 million and $0.9 million, respectively, of uncollectible receivables due to customer bankruptcies and other customer non-payments.

Terrorist Threats

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the United States government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, could be a future target of terrorist organizations. These developments have subjected our operations to increased risks. Any terrorist attack on our facilities, customers' facilities and, in some

cases, those of other pipelines, could have a material adverse effect on our business. We have increased security initiatives and are working with various governmental agencies to minimize risks associated with additional terrorist attacks.

Environmental

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of injunctions delaying or prohibiting certain activities and the need to perform investigatory and remedial activities. Although we believe our operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure you that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental laws and regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us. We believe that changes in environmental laws and regulations will not have a material adverse effect on our financial position, results of operations or cash flows in the near term.

In 1994, the LDEQ issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. At December 31, 2004, we have an accrued liability of $0.2 million for remediation costs at our Arcadia facility. Effective in March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On March 17, 2003, we experienced a release of 511 barrels of jet fuel from a storage tank at our Blue Island terminal located in Cook County, Illinois. As a result of the release, we have entered into an Agreed Order with the State of Illinois, which required us to conduct an environmental investigation. At this time, we have complied with the terms of the Agreed Order, and the results of the environmental investigation indicated there were no soil or groundwater impacts from the release. We are in the process of negotiating a final settlement with the State of Illinois, and we do not expect that compliance with the settlement will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 22, 2004, we experienced a release of approximately 12 barrels of jet fuel from a sump at our Lebanon, Ohio, terminal. The released jet fuel was contained within a storm water retention pond located on the terminal property. Six migratory waterfowl were affected by the jet fuel and were subsequently euthanized by or at the request of the USFWS. On October 1, 2004, the USFWS served us with a Notice of Violation, alleging that we violated 16 USC 703 of the Migratory Bird Treaty Act for the "take[ing] of migratory birds by illegal methods." On February 7, 2005, we entered into a Memorandum of Understanding with the USFWS, settling all aspects of this matter. The terms of this settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States DOJ of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the EPA, is seeking a civil penalty against us for alleged violations of the CWA arising out of this release. The maximum statutory penalty calculated for this alleged violation of the CWA is $2.8 million. We are in discussions with the DOJ regarding this matter and have responded to its request for additional information. We do not expect a civil penalty, if any, to have a material adverse effect on our financial position, results of operations or cash flows.

At December 31, 2004, we have an accrued liability of $5.0 million, related to various TCTM and TE Products sites requiring environmental remediation activities. At December 31, 2003, we had an accrued liability of $5.9 million related to various TCTM sites requiring environmental remediation activities. Under the terms of a 1998 agreement through which we acquired various crude oil assets from DETTCO, we received a five year contractual indemnity obligation for certain environmental liabilities attributable to the operations of the assets prior

to our acquisition. Concurrent with the expiration of this indemnity in 2003, we entered into a Settlement Agreement and Release with DETTCO releasing DETTCO from future obligations pertaining to certain environmental liabilities, requiring us to share in certain costs for the remediation of a crude oil site in Oklahoma, and the assumption of responsibility by DETTCO for environmental liabilities associated with three sites located in Texas and Oklahoma. We do not expect that the completion of remediation programs associated with TCTM and TE Products activities will have a future material adverse effect on our financial position, results of operations or cash flows.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 2. Summary of Significant Accounting Policies – New Accounting Pronouncements in the accompanying consolidated financial statements.

Disclosures About Effects of Transactions with Related Parties

The Partnership does not have any employees, and we are managed by the General Partner, an indirect wholly owned subsidiary of DEFS. Duke Energy holds an interest of approximately 70% in DEFS, and ConocoPhillips holds the remaining interest of approximately 30%. See Item 10. Directors and Executive Officers of the Registrant and Item 13. Certain Relationships and Related Transactions for discussion regarding transactions between us and DEFS, Duke Energy and ConocoPhillips.

Subsequent Event

On February 24, 2005, Texas Eastern Products Pipeline Company, LLC, our General Partner, was acquired by EPCO, Inc. ("EPCO"), a privately held company controlled by Dan L. Duncan. The acquisition was valued at $1.1 billion. Additionally, in a separate transaction, EPCO and its affiliates agreed to purchase 2.5 million of our Units, valued at approximately $100.0 million, from Duke Energy. EPCO and its affiliates own the general partner of Enterprise Products Partners L.P. ("Enterprise") and approximately 145 million Enterprise common units. Enterprise is one of the largest publicty traded master limited partnerships. The general partners of both TEPPCO Partners, L.P. ("TEPPCO") and Enterprise will continue to operate independently and will maintain separate boards of directors, management teams and offices.

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

We may be exposed to market risk through changes in crude oil commodity prices and interest rates. We do not have foreign exchange risks. Our Risk Management Committee has established policies to monitor and control these market risks. The Risk Management Committee is comprised, in part, of senior executives of the Company.

We seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. On the majority of our crude oil derivative contracts, we take the normal purchase and normal sale exclusion in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*.

Occasionally, customers require pricing terms which do not allow us to balance our position. Additionally, certain pricing terms may expose us to movements in margin. On a small portion of our crude oil marketing business, we enter into derivative contracts such as physical swaps and other business hedging devices for which we cannot take the normal purchase and normal sale exclusion and for which we do not elect hedge accounting. The terms of these contracts are less than one year. The purpose is to balance our position or lock in a margin and, as such, do not expose us to any additional significant market risk. We mark these transactions to market and the changes in the fair value are recognized in current earnings. This could potentially result in some financial statement variability during quarterly periods; however, any unrealized gains and losses reflected in the financial statements related to marking these transactions to market will be offset by realized gains and losses in different quarterly periods when the related physical transactions are settled.

At December 31, 2004, we had $353.0 million outstanding under our variable interest rate revolving credit facility. The interest rate is based, at our option, on either the lender's base rate plus a spread or LIBOR plus a spread in effect at the time of the borrowings and is adjusted monthly, bimonthly, quarterly or semiannually. Utilizing the balances of our variable interest rate debt outstanding at December 31, 2004, and assuming market interest rates increase 100 basis points, the potential annual increase in interest expense would be $3.5 million.

At December 31, 2004, TE Products had outstanding $180.0 million principal amount of 6.45% Senior Notes due 2008 and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively, the "TE Products Senior Notes"). At December 31, 2004, the estimated fair value of the TE Products Senior Notes was approximately $412.7 million. At December 31, 2004, we had outstanding $500.0 million principal amount of

7.625% Senior Notes due 2012 and $200.0 million principal amount of 6.125% Senior Notes due 2013. At December 31, 2004, the estimated fair value of the $500.0 million 7.625% Senior Notes and the $200.0 million 6.125% Senior Notes was approximately $569.6 million and $210.2 million, respectively.

We have utilized and expect to continue to utilize interest rate swap agreements to hedge a portion of our cash flow and fair value risks. Interest rate swap agreements are used to manage the fixed and floating interest rate mix of our total debt portfolio and overall cost of borrowing. Interest rate swaps that manage our cash flow risk reduce our exposure to increases in the benchmark interest rates underlying variable rate debt. Interest rate swaps that manage our fair value risks are intended to reduce our exposure to changes in the fair value of the fixed rate debt. Interest rate swap agreements involve the periodic exchange of payments without the exchange of the notional amount upon which the payments are based. The related amount payable to or receivable from counterparties is included as an adjustment to accrued interest.

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51%. During the years ended December 31, 2004, 2003 and 2002, we recognized reductions in interest expense of $9.6 million, $10.0 million and $8.6 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarter ended December 31, 2004, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of this interest rate swap was a gain of approximately $3.4 million at December 31, 2004, and a gain of approximately $2.3 million at December 31, 2003. Utilizing the balance of the 7.51% TE Products Senior Notes outstanding at December 31, 2004, and including the effects of hedging activities, assuming market interest rates increase 100 basis points, the potential annual increase in interest expense is $2.1 million.

In July 2000, we entered into an interest rate swap agreement to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. This interest rate swap matured in April 2004. We designated this swap agreement, which hedged exposure to variability in expected future cash flows attributed to changes in interest rates, as a cash flow hedge. The swap agreement was based on a notional amount of $250.0 million. Under the swap agreement, we paid a fixed rate of interest of 6.955% and received a floating rate based on a three-month U.S. Dollar LIBOR rate. Because this swap was designated as a cash flow hedge, the changes in fair value, to the extent the swap was effective, were recognized in other comprehensive income until the hedged interest costs were recognized in earnings. In June 2003, we repaid the amounts outstanding under our revolving credit facility with borrowings under a new three year revolving credit facility and canceled the old facility (see Note 10. Debt). We redesignated this interest rate swap as a hedge of our exposure to increases in the benchmark interest rate underlying the new variable rate revolving credit facility. During the years ended December 31, 2004, 2003 and 2002, we recognized increases in interest expense of $2.9 million, $14.4 million and $12.9 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap.

During 2003, we determined that we would repay a portion of the amount outstanding under the revolving credit facility with proceeds from our Unit offering in August 2003 (see Note 11. Partners' Capital and Distributions) resulting in a reduction of probable future interest payments under the credit facility. We reduced the outstanding balance of the revolving credit facility at December 31, 2003, to $210.0 million. During the year ended December 31, 2003, we recognized a loss of $1.0 million for the portion of the discontinued hedge. The total fair value of the interest rate swap was a loss of approximately $3.9 million at December 31, 2003. The remaining $2.9 million of other comprehensive income was transferred to earnings during the period from January 1, 2004, through the maturity of the interest rate swap in April 2004.

In February 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7.625% Senior Notes due 2012. The swap agreements had a combined notional amount of $500.0 million and matured in 2012 to match the principal and maturity of the Senior Notes. Under the swap agreements, we paid a floating rate of interest based on a U.S. Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7.625%. In July 2002, the swap agreements were terminated

resulting in a gain of approximately $18.0 million. Concurrent with the swap terminations, we entered into new interest rate swap agreements, with identical terms as the previous swap agreements; however, the floating rate of interest was based upon a spread of an additional 50 basis points. In December 2002, the swap agreements entered into in July 2002 were terminated, resulting in a gain of approximately $26.9 million. The gains realized from the July 2002 and December 2002 swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes. At December 31, 2004, the unamortized balance of the deferred gains was $36.6 million. In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the consolidated statement of income at the time of extinguishment.

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

Our consolidated financial statements, together with the independent registered public accounting firm's report of KPMG 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***

The principal executive officer and principal financial officer of our General Partner, after evaluating the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2004, have concluded that, as of such date, our disclosure controls and procedures are adequate and effective to ensure that material information relating to us and our consolidated subsidiaries would be made known to them by others within those entities.

Management's Annual Report on Internal Control over Financial Reporting

The management of Texas Eastern Products Pipeline Company, LLC, (the "General Partner"), the General Partner of TEPPCO Partners, L.P. (the "Partnership"), is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Partnership's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Partnership's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Partnership;

(ii) 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 Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the financial statements.

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on our assessment and those criteria, management believes that the Partnership maintained effective internal control over financial reporting as of December 31, 2004.

The Partnership's independent auditors have issued an attestation report on management's assessment of the Partnership's internal control over financial reporting. That report appears below.

/s/ BARRY R. PEARL

Barry R. Pearl
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

/s/ CHARLES H. LEONARD

Charles H. Leonard
Senior Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

Report of Independent Registered Public Accounting Firm

To the Partners of
TEPPCO Partners, L.P.:

We have audited management's assessment, included in the accompanying report titled Management's Annual Report on Internal Control over Financial Reporting included in Item 9A, that TEPPCO Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commissions (COSO). TEPPCO Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of TEPPCO Partners, L.P.'s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that TEPPCO Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, TEPPCO Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TEPPCO Partners, L.P. as of December 31, 2004 and 2003, and the related consolidated statements of income, partners' capital and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated February 24, 2005, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 24, 2005

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. As a result, no corrective actions were required or undertaken.

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

None.

PART III

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

Partnership Management

We do not directly have directors or officers, as is commonly the case with publicly traded partnerships. Our operations and activities are managed by the General Partner, which employs our management and operational personnel. The officers and directors of the General Partner are responsible for managing us. All directors of the General Partner are elected annually by DEFS. All officers serve at the discretion of the directors. None of the officers of the General Partner serve as officers or employees of DEFS or any other parent-affiliated company.

Because we are a limited partnership, we meet the definition of a "controlled company" under the listing standards of the New York Stock Exchange. Accordingly, we and our General Partner are not required to have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

Committees of the Board of Directors

Audit Committee

Our General Partner has an audit committee (the "Audit Committee") comprised of three board members who are "independent" as that term is defined in Rule 10A-3 of the Exchange Act and as that term is used in applicable listing standards of the New York Stock Exchange. The members of the Audit Committee are Paul F. Ferguson, Jr. (Chairman), John P. DesBarres and Milton Carroll. The members of the Audit Committee are non-employee directors of the General Partner and are not officers, directors or otherwise affiliated with DEFS or its parent companies, ConocoPhillips or Duke Energy. No member of the Audit Committee of our General Partner serves on the audit committees of more than three public companies. Our Board of Directors has determined that no Audit Committee member has a material relationship with the Company. Our Board of Directors has also determined that Mr. Ferguson qualifies as an audit committee financial expert as defined in Item 401(h) of Regulation S-K.

The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the independent auditors. The Audit Committee also reviews the scope and quality, including the independence and objectivity of the independent and internal auditors. The Audit Committee has sole authority as to the retention, evaluation, compensation and oversight of the work of the independent auditors. The independent auditors report directly to the Audit Committee. The Audit Committee also has sole authority to approve all audit and non-audit services provided by the independent auditors and shall ensure that the independent auditors are not engaged to perform specific non-audit services prohibited by law or regulation. The charter of the Audit Committee is filed as an exhibit to this Annual Report on Form 10-K and is available on our website at www.teppco.com.

Our Audit Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our Audit Committee may do so by calling 1-800-799-4607.

Special Committee

The Special Committee is a standing committee of the Board of Directors of the General Partner and is composed of three independent directors, John P. DesBarres (Chairman), Milton Carroll and Paul F. Ferguson, Jr. The members of the Special Committee are non-employee directors of the General Partner and are not officers, directors or otherwise affiliated with DEFS or its parent companies, ConocoPhillips or Duke Energy. The Special Committee is responsible for the independent evaluation of the fairness and reasonableness of affiliate transactions and the approval or rejection of those transactions that would ordinarily require board approval involving the General Partner, DEFS or an affiliate of either, and us. Such transactions include related party asset sales and operating agreements. The Special Committee is also responsible for the evaluation of the fairness and approval or rejection of the issuance and pricing of additional Units and debt.

Compensation Committee

The Compensation Committee is a standing committee of the Board of Directors of the General Partner and is composed of five directors, Jim W. Mogg (Chairman), Milton Carroll, Derrill Cody, John P. DesBarres and Paul F. Ferguson, Jr. The Compensation Committee establishes and maintains competitive and equitable compensation and employment policies to retain the management required to carry out our business, to stimulate their useful and profitable efforts on our behalf and to attract necessary additions to management with appropriate qualifications. The Compensation Committee also recommends to the Board of Directors the election of officers and reviews the management succession plans for senior officer positions.

Code of Ethics, Corporate Governance Guidelines and Charter of the Audit Committee

We have adopted a Code of Ethics applicable to all employees, including the principal executive officer, principal financial officer and directors of the General Partner. A copy of the Code of Ethics is available on our

website at www.teppco.com under Corporate Governance. We intend to post on our website any amendments to, or waivers from, our Code of Ethics applicable to our senior officers.

Our Corporate Governance Guidelines address director qualification standards; director access to management, and as necessary and appropriate, independent advisors; director compensation; director orientation and continuing education; management succession and annual performance evaluation of the board. The Charter of our Audit Committee and our Corporate Governance Guidelines are currently available on our website at www.teppco.com under Corporate Governance. Additionally, the Code of Ethics, our Corporate Governance Guidelines and the Charter of the Audit Committee are available in print to any person who requests the information. Persons wishing to obtain this printed material should submit a request in care of Secretary, TEPPCO Partners, L.P., 2929 Allen Parkway, P.O. Box 2521, Houston, Texas 77252-2521.

NYSE Corporate Governance Listing Standards

Annual CEO Certification

As the Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, as General Partner of TEPPCO Partners, L.P., and as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, I hereby certify that as of the date hereof I am not aware of any violation of the Company of NYSE's Corporate Governance listing standards, other than has been notified to the Exchange pursuant to Section 303A.12(b) and disclosed as an attachment hereto.

/s/ BARRY R. PEARL

Barry R. Pearl
Chief Executive Officer and President
Texas Eastern Products Pipeline Company, LLC
October 28, 2004

Executive Sessions of Non-Management Directors

Mark A. Borer, Michael J. Bradley, Milton Carroll, Derrill Cody, John P. DesBarres, William H. Easter III, Paul F. Ferguson, Jr. and Jim W. Mogg, who are non-management directors of our General Partner, meet at regularly scheduled executive sessions without management. Mr. Mogg serves as the presiding director at those executive sessions. Persons wishing to communicate with the Company's non-management directors may do so by calling 1-800-799-4607.

Milton Carroll, John P. DesBarres and Paul F. Ferguson, Jr., who are independent non-management directors of our General Partner, meet at least annually in executive session without management and the other directors. The chairs of the Audit Committee and the Special Committee of the Board of Directors rotate on an annual basis as the chair of the independent non-management directors. The chair for 2005 is Paul F. Ferguson, Jr. Persons wishing to communicate with the Company's independent non-management directors may do so by calling 1-800-799-4607.

Directors and Executive Officers

The following table sets forth certain information with respect to the directors and executive officers of the General Partner.

Name	Age	Position with Our General Partner
Jim W. Mogg	56	Chairman of the Board, Member of the Compensation* Committee and Director
Mark A. Borer	50	Director
Michael J. Bradley	50	Director
Milton Carroll	54	Director and Member of the Compensation, Special and Audit Committees
Derrill Cody	66	Director and Member of the Compensation Committee
John P. DesBarres	65	Director and Member of the Compensation, Special* and Audit Committees
William H. Easter III	55	Director
Paul F. Ferguson, Jr.	55	Director and Member of the Compensation, Special and Audit* Committees
Barry R. Pearl+	55	President, Chief Executive Officer and Director
Charles H. Leonard+	56	Senior Vice President and Chief Financial Officer
J. Michael Cockrell+	58	Senior Vice President of Commercial Upstream
Thomas R. Harper+	64	Senior Vice President of Commercial Downstream
Leonard W. Mallett+	48	Senior Vice President of Operations
James C. Ruth+	57	Senior Vice President, General Counsel and Secretary
Barbara A. Carroll+	50	Vice President of Environmental, Health and Safety
John N. Goodpasture+	56	Vice President of Corporate Development
Stephen W. Russell+	53	Vice President of Support Services
C. Bruce Shaffer+	46	Vice President of Human Resources and Ethics and Compliance Officer

* Indicates Chairman of committee
+ Indicates employment contract with the General Partner (see Executive Employment Contracts and Termination of Employment Arrangements)

Jim W. Mogg was elected a director of the General Partner in October 1997, Chairman of the Compensation Committee in April 2000 and Chairman of the Board in May 2002. Mr. Mogg succeeded William L. Thacker as Chairman of the Board in May 2002, when Mr. Thacker retired as Chairman. Prior to being elected Chairman of the Board in 2002, Mr. Mogg served as Vice Chairman of the Board from April 2000 to April 2002. Mr. Mogg was named group vice president and chief development officer of Duke Energy, effective January 1, 2004. He served as chairman, president and chief executive officer of DEFS from December 1999 to December 2003. Mr. Mogg was previously president of Centana Energy Corporation, a subsidiary of a predecessor of Duke Energy, from 1992 to 1999. He joined Duke Energy in 1973 in the gas supply department of Panhandle Eastern Pipe Line Company.

Mark A. Borer was elected a director of the General Partner in April 2000. Mr. Borer is group vice president, marketing and corporate development of DEFS, having been elected to that position in December 2004. He was previously executive vice president of marketing and corporate development of DEFS from April 2002 to December 2004. Mr. Borer previously served as senior vice president, Southern Division, having been elected to that position in 1999 when Union Pacific Fuels, Inc. was acquired by DEFS. Before joining DEFS, he was vice president of natural gas marketing for Union Pacific Fuels, Inc. from 1992 until 1999.

Michael J. Bradley was elected a director of the General Partner in February 2003. Mr. Bradley is group vice president, gathering and processing of DEFS, having been elected to that position in December 2004. He was previously executive vice president, gathering and processing of DEFS, from April 2002 until December 2004. Mr. Bradley previously served as senior vice president, Northern Division, for DEFS, having been elected to that position in 1999. Mr. Bradley joined DEFS in 1979 and served in a variety of positions in marketing, business development and operations.

Milton Carroll was elected a director of the General Partner in November 1997 and is a member of the Compensation Committee, Special Committee and the Audit Committee. He served as Chairman of the Audit Committee from April 2000 until January 16, 2003. Mr. Carroll is the chairman of CenterPoint Energy, Inc., having been elected in September 2002. Mr. Carroll is the founder and chairman of Instrument Products, Inc., a manufacturer of oil field equipment since 1977. Mr. Carroll is a director of Devon Energy Corporation, Eagle Global Logistics and Chairman of the Board of Health Care Service Corporation.

Derrill Cody was elected a director of the General Partner in 1989. He is a member of the Compensation Committee and was Chairman of the Audit Committee from April 1990 until April 2000. Mr. Cody is currently of counsel to McKinney and Stringer, P. C., which represents Duke Energy, DEFS and us in certain matters. Mr. Cody served as chief executive officer of Texas Eastern Gas Pipeline Company from 1987 to 1990. Prior to that, he was executive vice president of Kerr McGee Corporation. Mr. Cody is a director of CenterPoint Energy, Inc.

John P. DesBarres was elected a director of the General Partner in May 1995. He is a member of the Compensation and Audit Committees and serves as Chairman of the Special Committee. Mr. DesBarres was formerly chairman, president and chief executive officer of Transco Energy Company from 1992 to 1995. He joined Transco in 1991 as president and chief executive officer. Prior to joining Transco, Mr. DesBarres served as chairman, president and chief executive officer for Santa Fe Pacific Pipelines, Inc. from 1988 to 1991. Mr. DesBarres is a director of American Electric Power and Penn Virginia G.P., LLC, an indirect wholly owned subsidiary of Penn Virginia Corporation, which is the general partner of Penn Virginia Resource Partners, L.P.

William H. Easter III was elected a director of the General Partner in February 2004. Mr. Easter is chairman, president and chief executive officer of DEFS, having been elected to that position in January 2004. Mr. Easter joined ConocoPhillips (formerly Conoco Inc.) in 1971 and served in a variety of positions, most recently as general manager of Gulf Coast businesses unit in Lake Charles, Louisiana, from 1998 until 2002 and vice president of state government affairs for ConocoPhillips from 2002 until December 2003.

Paul F. Ferguson, Jr. was elected director of the General Partner in October 2004, and is a member of the Compensation, Audit and Special Committees. He was elected Chairman of the Audit Committee in October 2004. Mr. Ferguson served as senior vice president and treasurer of Duke Energy from June 1997 to June 1998, when he retired. Mr. Ferguson served as senior vice president and chief financial officer of PanEnergy Corp. from September 1995 to June 1997. He held various other financial positions with PanEnergy Corp. from 1988 to 1995, and served as treasurer of Texas Eastern Corporation from 1988 to 1989.

Barry R. Pearl was elected President of the General Partner in February 2001 and Chief Executive Officer and director in May 2002. He succeeded William L. Thacker as Chief Executive Officer in May 2002, when Mr. Thacker retired as Chief Executive Officer. Mr. Pearl was previously Chief Operating Officer from February 2001 until May 2002. Prior to joining the Company, Mr. Pearl was vice president – finance and administration, treasurer, secretary and chief financial officer of Maverick Tube Corporation from June 1998. Mr. Pearl was senior vice president and chief financial officer of Santa Fe Pacific Pipeline Partners, L.P. from 1995 until 1998, and senior vice president, business development from 1992 to 1995.

Charles H. Leonard is Senior Vice President and Chief Financial Officer of the General Partner. Mr. Leonard joined the Company in 1988 as Vice President and Controller. In November 1989, he was elected Vice President and Chief Financial Officer. He was elected Senior Vice President in March 1990, and was Treasurer from October 1996 until May 2002.

J. Michael Cockrell is Senior Vice President, Commercial Upstream of the General Partner, having been elected in February 2003. Mr. Cockrell was previously Vice President, Commercial Upstream from September 2000 until February 2003. He was elected Vice President of the General Partner in January 1999 and also serves as President of TEPPCO Crude GP, LLC. He joined PanEnergy in 1987 and served in a variety of positions in supply and development, including president of DETTCO.

Thomas R. Harper is Senior Vice President, Commercial Downstream of the General Partner, having been elected in February 2003. Mr. Harper was previously Vice President, Commercial Downstream from September

2000 until February 2003 and Vice President, Product Transportation and Refined Products Marketing from 1988 until September 2000. Mr. Harper joined the Company in 1987 as Director of Product Transportation.

Leonard W. Mallett is Senior Vice President, Operations of the General Partner, having been elected in February 2005. He was previously Vice President, Operations from September 2000 until February 2005. Mr. Mallett was previously Region Manager of the Southwest Region of the Company from 1994 until 1999 and Director of Engineering, from 1992 until 1994. Mr. Mallett joined the Company in 1979 as an engineer.

James C. Ruth is Senior Vice President, General Counsel and Secretary of the General Partner, having been elected in February 2001. Mr. Ruth was previously Vice President and General Counsel and Secretary from 1998 until February 2001, and Vice President, General Counsel from 1991 until 1998. Mr. Ruth joined the Company in 1970.

Barbara A. Carroll is Vice President, Environmental, Health and Safety, having been elected in February 2002. Ms. Carroll joined ExxonMobil in 1990 and served in a variety of management positions, including Procurement Services Manager, Materials and Service Manager and Baytown Area Public Affairs Manager until she joined the Company in February 2002. Prior to ExxonMobil, Ms. Carroll was General Manager, Corporate Environmental Protection and Compliance with Panhandle Eastern Corporation. Ms. Carroll is not related to Milton Carroll.

John N. Goodpasture is Vice President, Corporate Development of the General Partner, having joined the Company in November 2001. Mr. Goodpasture was previously Vice President of Business Development for Enron Transportation Services from June 1999 until he joined the Company. Prior to his employment at Enron Transportation Services, Mr. Goodpasture spent 19 years in various executive positions at Seagull Energy Corporation (now Devon Energy Corporation), a large independent oil and gas company. At Seagull Energy, Mr. Goodpasture had most recently served for over ten years as Senior Vice President, Pipelines and Marketing.

Stephen W. Russell is Vice President, Support Services of the General Partner, having been elected in September 2000. Mr. Russell was previously Region Manager of the Southwest Region from July 1999 until September 2000, and Technical Operations Superintendent of the Southwest Region from 1994 until 1999. Mr. Russell joined the Company in 1988 as Project Manager in Engineering.

C. Bruce Shaffer is Vice President, Human Resources and Ethics and Compliance Officer of the General Partner, having been elected in February 2005. Mr. Shaffer joined the Company in August 2004 supporting Human Resources. He was previously Vice President of Human Resources Services for Duke Energy Gas Transmission and Duke Energy Americas from January 2004 until July 2004 and Vice President of Human Resources for Duke Energy North America from June 2003 until July 2004. Mr. Shaffer joined Duke Energy in January 2000 as Managing Director of Human Resources for Duke Energy North America and Duke Energy International.

In addition to our Executive Officers, Mark G. Stockard serves as Treasurer, having been elected in May 2002. Mr. Stockard was Assistant Treasurer of the General Partner from July 2001 until May 2002. He was previously Controller from October 1996 until May 2002. Mr. Stockard joined the Company in October 1990.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of such equity securities. Based on information furnished to the Company and written representation that no other reports were required, to the Company's knowledge, all applicable Section 16(a) filing requirements were complied with during the year ended December 31, 2004, except for a report covering a transaction that was filed late by Mr. Mallett.

Item 11. *Executive Compensation*

Summary Compensation Table

The officers of the General Partner manage and operate our business. We do not directly employ any of the persons responsible for managing or operating our operations, but instead reimburse the General Partner for the services of these persons (see Note 7. Related Party Transactions). The following table reflects cash compensation paid or accrued by the General Partner for the years ended December 31, 2004, 2003 and 2002, with respect to its Chief Executive Officer and the four other most highly compensated executive officers in 2004 (collectively, the "Named Executive Officers").

SUMMARY COMPENSATION TABLE

Name and Principal Position	Annual Compensation Year	Salary ($)	Bonus ($) (2)	Other Annual Compensation ($) (3)	Long Term Compensation Payouts ($) (4)	All Other Compensation ($) (5)
Barry R. Pearl (1)	2004	291,738	157,242	59,431	291,910	31,321
President and Chief	2003	283,500	196,465	52,000	—	27,608
Executive Officer	2002	252,308	142,000	24,160	—	24,310
J. Michael Cockrell	2004	209,654	91,451	12,021	—	32,714
Senior Vice President,	2003	202,846	114,364	7,250	108,225	69,078
Commercial Upstream	2002	195,462	86,600	21,750	358,200	27,034
James C. Ruth	2004	208,308	88,218	14,906	183,106	34,069
Senior Vice President and	2003	195,654	108,333	20,250	456,084	864,675
General Counsel	2002	182,342	86,300	18,095	55,368	29,024
Charles H. Leonard	2004	202,654	86,391	14,906	183,106	325,281
Senior Vice President and	2003	195,654	108,800	20,250	271,523	22,007
Chief Financial Officer	2002	182,342	88,200	18,095	32,062	23,991
Thomas R. Harper	2004	197,115	84,365	12,322	139,300	29,646
Senior Vice President,	2003	181,154	102,135	15,500	493,052	25,334
Commercial Downstream	2002	161,488	79,500	14,805	37,460	23,622

(1) Mr. Pearl was elected as Chief Executive Officer and director effective May 1, 2002.

(2) Amounts represent bonuses accrued during the year under the Management Incentive Compensation Plan ("MICP"). Payments under the MICP are made in the subsequent year. Annual compensation does not include awards under long-term incentive plans, which are described in the 2000 LTIP awards table under "Compensation Pursuant to General Partner Plans".

(3) Amounts represent quarterly distribution equivalents under the terms of the Company's 2000 Long Term Incentive Plan ("2000 LTIP") and Phantom Unit Retention Plan ("PURP").

(4) Amounts represent credits earned to Performance Unit accounts and payouts under the 2000 LTIP.

(5) Includes (i) Company matching contributions under funded, qualified, defined contribution retirement plans; (ii) Company matching contribution credits under unfunded, non qualified plans; (iii) the imputed value of premiums paid by the Company for insurance on the Named Executive Officers' lives; and (iv) payments received under the Duke Energy Retirement Cash Balance Plan.

Executive Employment Contracts and Termination of Employment Arrangements

On February 12, 2001, Barry R. Pearl and the Company entered into an employment agreement, which set a minimum base salary of $220,000 per year. The Company may terminate the employment agreement for cause, death or disability. In addition, the Company or Mr. Pearl may terminate the agreement upon written notice. Mr. Pearl participates in other Company sponsored benefit plans on the same basis as other senior executives of the Company. In the event Mr. Pearl is terminated due to death or disability or by the Company for cause, Mr. Pearl is entitled only to base salary earned through the date of termination. In the event of termination for any other reason, Mr. Pearl is entitled to base salary earned through the date of termination plus a lump sum severance payment equal to two times his base annual salary and two times the current target bonus approved under the MICP by the Compensation Committee. In the event Mr. Pearl is involuntarily terminated following a change in control, he is entitled to a lump sum severance payment equal to two times his base annual salary plus two times his current target bonus.

The Company has entered into employment agreements with its executive officers identified in Item 10. Directors and Executive Officers of the Registrant. The agreements may be terminated for death, disability or by the Company with or without cause. In the event one of the named executives' employment is terminated due to death or disability or by the Company for cause, the executive is entitled only to base salary earned through the date of termination. In the event of termination for any other reason, the executive is entitled to base salary earned through the date of termination plus a lump sum severance payment equal to two times such executive's base annual salary and two times the current target bonus approved under the MICP by the Compensation Committee. In the event that an executive is involuntarily terminated following a change in control, the executive is entitled to a lump sum severance payment equal to two times his base annual salary plus two times his current target bonus.

Compensation Committee Interlocks and Insider Participation

During 2004, Jim W. Mogg, a director of the General Partner and group vice president and chief development officer of Duke Energy, was chairman of the Compensation Committee of the General Partner and participated in deliberations concerning the General Partner's executive officer compensation. The other four members of the Compensation Committee of the General Partner, Milton Carroll, Derrill Cody, John P. DesBarres and Paul F. Ferguson, Jr., are non-employee directors of the General Partner and are not officers or directors of DEFS or its parent companies, ConocoPhillips or Duke Energy.

Compensation Pursuant to General Partner Plans

Management Incentive Compensation Plan

The General Partner has established the MICP, which provides for the payment of additional cash compensation to participants if certain Partnership performance objectives and personal objectives are met each year. The Compensation Committee of the Board of Directors of the General Partner determines at the beginning of each year which employees are eligible to become participants in the MICP. Additional participants may be added to the plan during the year by the Chief Executive Officer. Each participant is assigned a target award, determined as a percentage of total annual eligible earnings for the plan year less any incentive compensation payments during the plan year, by the Compensation Committee. Such target award determines the additional compensation to be paid if certain performance objectives and personal objectives are met. The amount of the target awards may range from 10% to 55% of a participant's base salary. Maximum payout under the MICP is 144% of a participant's target award. Awards are paid as soon as practicable following approval by the Compensation Committee after the close of a year.

1994 Long Term Incentive Plan

During 1994, the Company adopted the Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan ("1994 LTIP"). The 1994 LTIP provides certain key employees with an incentive award whereby a participant is granted an option to purchase Units. These same employees are also granted a stipulated number of Performance Units, the cash value of which may be used to pay for the exercise of the respective Unit options awarded. Under the provisions of the 1994 LTIP, no more than one million options and two million Performance

Units may be granted. No awards have been made under the 1994 LTIP since 1999, and none are expected to be made in the future.

There were no Aggregated Option Exercises during the year ended December 31, 2004, under the 1994 LTIP by the Named Executive Officers, and there were no unexercised outstanding Unit options under the 1994 LTIP to the Named Executive Officers as of December 31, 2004.

2000 Long Term Incentive Plan

Effective January 1, 2000, the General Partner established the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period.

The performance period applicable to awards granted in 2004 is the three-year period that commenced on January 1, 2004, and ends on December 31, 2006. Each participant's performance percentage is the result of 100% +/- [(A) minus (C)] divided by [(C) minus (B)] where (A) is the actual Economic Value Added for the performance period, (B) is $67.6 million (which represents the actual Economic Value Added for the three-year period immediately preceding the performance period) and (C) is $103.3 million (which represents the Target Economic Value Added during the three-year performance period). No amounts will be payable under the awards granted in 2004 for the 2000 LTIP unless Economic Value Added for the three year performance period exceeds $67.6 million. The performance percentage may not exceed 150%.

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. For purposes of the 2000 LTIP for plan years 2000 through 2002, EBITDA means our earnings before net interest expense, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that in its discretion the Compensation Committee of the General Partner may exclude gains or losses from extraordinary, unusual or non-recurring items. For the years ended December 31, 2004 and 2003, EBITDA means, in addition to the above, earnings before other income – net. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, *plus* products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by the Compensation Committee at the date of award grant.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award.

The following table provides information concerning awards under the 2000 LTIP to each of the Named Executive Officers during 2004.

Name	Number of Phantom Units	Performance Period	Estimated Future Payouts (1) Threshold (#) (2)	Target (#) (3)	Maximum (#) (4)
Mr. Pearl	7,100	3 years	—	7,100	10,650
Mr. Leonard	2,200	3 years	—	2,200	3,300
Mr. Ruth	2,200	3 years	—	2,200	3,300
Mr. Cockrell	2,200	3 years	—	2,200	3,300
Mr. Harper	2,100	3 years	—	2,100	3,150

(1) Phantom units will be settled in cash based upon the then market price of the Units at the end of the performance period as described above.

(2) No amounts will be payable for awards granted in 2004 unless Economic Value Added for the three year performance period exceeds $67.6 million.

(3) In number of phantom units. Pursuant to Instruction 5 to Regulation 402(e) of the Securities and Exchange Commission, these amounts assume that the 13% increase in Economic Value Added for 2004 as compared with 2003 is maintained for each of the three years in the performance period. There can be no assurance that any specific amount of Economic Value Added will be attained for such period.

(4) The maximum potential payout under the 2000 LTIP is 150% of phantom units awarded.

Pension Plan

Prior to the transfer of the General Partner interest from Duke Energy to DEFS on April 1, 2000, the Company's employees participated in the Duke Energy Retirement Cash Balance Plan, which is a noncontributory, trustee-administered pension plan. Effective January 1, 1999, the benefit formula for all eligible employees was a cash balance formula. Under a cash balance formula, a plan participant accumulated a retirement benefit based upon pay credits and current interest credits. The pay credits were based on a participant's salary, age, and service. In addition, the Named Executive Officers participated in the Duke Energy Executive Cash Balance Plan, which is a noncontributory, nonqualified, defined benefit retirement plan. The Duke Energy Executive Cash Balance Plan was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans.

Benefits under the Duke Energy Retirement Cash Balance Plan and the Duke Energy Executive Cash Balance Plan were based on eligible pay, generally consisting of base pay, short term incentive pay and lump-sum merit increases. The Duke Energy Retirement Cash Balance Plan excludes deferred compensation, other than deferrals pursuant to Sections 401(k) and 125 of the Internal Revenue Code. All benefits owed to the Named Executive Officers under the Duke Energy Retirement Cash Balance Plan have been paid. As part of the change in ownership on March 31, 2000, the Company is no longer responsible for the funding of the liabilities associated with the Duke Energy Executive Cash Balance Plan.

Effective April 1, 2000, the Company adopted the TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") and the TEPPCO Supplemental Benefit Plan ("TEPPCO SBP"). The benefits and provisions of these plans are substantially identical to the Duke Energy Retirement Cash Balance Plan and the Duke Energy Executive Cash Balance Plan previously in effect prior to April 1, 2000.

Under the cash balance benefit accrual formula that applies in determining benefits under the TEPPCO RCBP, an eligible employee's plan account receives a pay credit at the end of each month in which the employee remains eligible and receives eligible pay for services. The monthly pay credit is equal to a percentage of the employee's monthly eligible pay. The percentage depends on age added to completed years of services at the beginning of the year, as shown below:

Age plus Service	Monthly Pay Credit Percentage
34 or less	4%
35 to 49	5%
50 to 64	6%
65 or more	7%

The above monthly pay credit is increased by an additional 4% of any portion of eligible pay above the Social Security taxable wage base ($87,900 for 2004). Employee accounts also receive monthly interest credits on their balances. The rate of the interest credit is adjusted quarterly and is derived from the average annual yield on 30-year U.S. Treasury Bonds during the third week of the last month of the previous quarter, subject to a minimum rate of 4% per year and a maximum rate of 9% per year.

Assuming that the Named Executive Officers continue in their present positions at their present salaries until retirement at age 65, their estimated annual pensions in a single life annuity form under the applicable pension plan(s) (including the Duke Energy Executive Cash Balance Plan, the TEPPCO RCBP and the TEPPCO SBP) attributable to such salaries would be as follows: Barry R. Pearl, $73,596; J. Michael Cockrell, $40,571; James C. Ruth, $61,862; Charles H. Leonard, $72,531; and Thomas R. Harper, $15,191. Such estimates were calculated assuming interest credits at a rate of 6% per annum and using a future Social Security taxable wage base equal to $90,000.

Compensation of Directors

Directors of the General Partner who are neither officers nor employees of either the Company or DEFS receive a stipend, effective January 1, 2005, of $35,000 per annum, $1,000 for attendance at each meeting of the Board of Directors, $1,000 for attendance at each meeting of a committee of the Board of Directors, except for attendance of the Audit Committee, for which the amount is $2,000 for each meeting, and reimbursement of expenses incurred in connection with attendance at a meeting of the Board of Directors or a committee of the Board of Directors. Each non-employee director who serves as chairman of a committee of the Board of Directors receives an additional stipend of $8,000 per annum, except for the chairman of the Audit Committee, who receives an additional stipend of $20,000 per annum. Effective September 1, 1999, non-employee directors may elect to defer payment of retainer and attendance fees until termination of service on the Board of Directors. Such deferral may be either 50% or 100% in either a fixed income investment account that is credited with annual interest (currently 7%) or an investment account based upon the market value of Units.

Effective January 1, 2004, each quarter that a non-employee director continues to serve on the Board of Directors, such director will be credited with an amount equal to the then current market value of 100 Units and distribution equivalents on previously awarded amounts. In general, such amounts will not become distributable until the non-employee director terminates service on the Board of Directors. When a non-employee director terminates service on the Board of Directors, payment will be distributed in cash to the director according to the distribution schedule chosen by such director.

Messrs. Mogg, Pearl, Borer, Bradley and Easter are not compensated for their services as directors, and it is not anticipated that any compensation for service as a director will be paid in the future to directors who are either officers or full-time employees of Duke Energy, DEFS, the General Partner or any of their affiliates.

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

Equity Compensation Plan Information

At December 31, 2004, we had no Equity Compensation Plans approved or unapproved by security holders as none of our compensation plans require the issuance of securities or options. During the year ended December 31, 2003, all of the remaining outstanding Unit options under the 1994 LTIP were exercised (see Compensation Pursuant to General Partner Plans). We have no other compensation plans that would result in the issuance of Units.

Security Ownership of Certain Beneficial Owners

As of February 23, 2005, Duke Energy, through its ownership of the Company and other subsidiaries, owns 2,500,000 Units, representing 4.0% of the 63.0 million Units outstanding. No other person is known by us to own more than 5% of our outstanding Units. On February 24, 2005, our General Partner was acquired by EPCO, a privately held company controlled by Dan L. Duncan. Additionally, in a separate transaction, EPCO and its affiliates have agreed to purchase the 2.5 million Units from Duke Energy, valued at approximately $100.0 million (see Note 21. Subsequent Event).

Security Ownership of Management

The following table sets forth certain information, as of February 25, 2005, concerning the beneficial ownership of Units by each director and Named Executive Officer of the General Partner and by all directors and officers of the General Partner as a group. This information is based on data furnished by the persons named. Based on information furnished to the General Partner by these persons, no director or officer of the General Partner owned beneficially, as of February 25, 2005, more than 1% of the 63.0 million Units outstanding at that date.

Name	Number of Units (1)
Jim W. Mogg (2)	4,427
Mark A. Borer	1,000
Michael J. Bradley	1,150
Derrill Cody	13,000
John P. DesBarres (3)	20,000
Paul F. Ferguson, Jr.	200
Barry R. Pearl	10,000
J. Michael Cockrell	5,000

Thomas R. Harper	10,000
James C. Ruth	5,000
Charles H. Leonard	1,124
All directors and officers (consisting of 18 people, including those named above)	72,737

(1) Unless otherwise indicated, the persons named above have sole voting and investment power over the Units reported. Includes Units that the named person has the right to acquire within 60 days.

(2) Includes 2,227 Units owned by daughters.

(3) Units are held jointly with spouse with right of survivorship.

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

Our Management

We have no employees and are managed by the Company, an indirect wholly owned subsidiary of DEFS. Duke Energy holds an interest of approximately 70% in DEFS, and ConocoPhillips holds the remaining interest of approximately 30%. According to the Partnership Agreements, the Company is entitled to reimbursement of all direct and indirect expenses related to our business activities (see Note 1. Partnership Organization).

For the years ended December 31, 2004, 2003, and 2002, we incurred direct expenses of $83.6 million, $78.0 million and $66.7 million, respectively, which were charged to us by DEFS. Substantially all of these costs were related to payroll and payroll related expenses. For the years ended December 31, 2004, 2003, and 2002, expenses for administrative services and overhead allocated to us by Duke Energy and its affiliates were $1.2 million, $1.1 million and $0.8 million, respectively.

Transactions with DEFS and its affiliates

TCO purchases condensate from DEFS and its affiliates. For the years ended December 31, 2004, 2003, and 2002, TCO's purchases from DEFS and its affiliates were $141.3 million, $110.7 million and $80.5 million, respectively.

LSI sells lubrication oils and specialty chemicals to DEFS. For the years ended December 31, 2004, 2003, and 2002, revenues recognized by LSI included $16.1 million, $15.2 million and $14.6 million, respectively, for the sale of lubrication oils and specialty chemicals to DEFS.

Effective with the purchase of fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into a 20-year Fractionation Agreement, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Revenues recognized from the fractionation facilities totaled $7.5 million, $7.4 million and $7.4 million for the years ended December 31, 2004, 2003 and 2002, respectively. TEPPCO Colorado and DEFS also entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS. Expenses related to the Operation and Maintenance Agreement totaled $0.9 million for each of the years ended December 31, 2004, 2003 and 2002.

The Dean Pipeline and the Wilcox Pipeline were included with the crude oil assets purchased from DEFS effective November 1, 1998. The southern portion of the Dean Pipeline originates in South Texas and transports NGLs for DEFS into its pipeline in Point Comfort, Texas. Revenues recognized from DEFS for NGL transportation totaled $0.2 million, $1.0 million and $2.9 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Wilcox Pipeline, which is located along the Texas Gulf Coast, transports NGLs for DEFS from two of its natural gas processing plants and is currently supported by a throughput agreement with DEFS through November 2005. The fees paid to us by DEFS under the agreement were $1.4 million, $1.5 million and $1.2 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The Panola Pipeline and San Jacinto Pipeline were purchased on December 31, 2000, from DEFS for $91.7 million. These pipelines originate at DEFS' East Texas Plant Complex in Panola County, Texas, and transport NGLs for DEFS and other major integrated oil and gas companies. Revenues recognized from an affiliate of DEFS for NGL transportation totaled $11.3 million, $9.2 million and $12.0 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Effective May 2001, we entered into an agreement with an affiliate of DEFS to commit to it sole utilization of our Providence terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. The agreement was renegotiated in May 2004. During the years ended December 31, 2004, 2003 and 2002, revenues of $4.3 million, $3.2 million and $2.3 million, respectively, from an affiliate of DEFS were recognized pursuant to this agreement.

On September 30, 2001, we purchased Jonah (see Note 5. Acquisitions and Dispositions). The Jonah assets are managed and operated by employees of DEFS under a contractual agreement under which DEFS is reimbursed for its actual costs. During the years ended December 31, 2004, 2003 and 2002, we recognized $4.1 million, $3.7 million and $3.3 million, respectively, of expenses related to the operation and management of the Jonah assets by DEFS. Jonah provides gas gathering services to an affiliate of DEFS. The gathering fees paid to us by an affiliate of DEFS totaled $3.3 million, $2.0 million and $1.2 million for the years ended December 31, 2004, 2003 and 2002, respectively. In connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004, Jonah sells NGLs to, and purchases gas from, an affiliate of DEFS. For the year ended December 31, 2004, Jonah's sales to DEFS and its affiliates were $7.1 million, and purchases from DEFS and its affiliates were $5.1 million. In addition, processing fees we received from an affiliate of DEFS for gas processing services at the Pioneer plant totaled $0.6 million for the year ended December 31, 2004.

On March 1, 2002, we purchased the Chaparral NGL system (see Note 5. Acquisitions and Dispositions). The Chaparral assets are managed and operated by employees of DEFS under a contractual agreement under which DEFS is reimbursed for its actual costs. During the years ended December 31, 2004, 2003, and 2002, we recognized

$2.3 million, $2.1 million and $1.7 million, respectively, of expenses related to the operation and management of the Chaparral assets by DEFS. An affiliate of DEFS transports NGLs on the Chaparral NGL system. The fees paid to us by an affiliate of DEFS for NGL transportation on the Chaparral NGL system totaled $3.8 million, $5.5 million and $4.5 million for the years ended December 31, 2004, 2003 and 2002, respectively.

On June 30, 2002, we purchased Val Verde (see Note 5. Acquisitions and Dispositions). The Val Verde assets are managed and operated by employees of DEFS under a contractual agreement under which DEFS is reimbursed for its actual costs. During the years ended December 31, 2004, 2003, and 2002, we recognized $3.8 million, $3.0 million and $1.2 million, respectively, of expenses related to the operation and management of the Val Verde assets by DEFS.

At December 31, 2004 and 2003, we had a receivable from DEFS of $10.5 million and $1.8 million, respectively, related to sales and transportation services provided to DEFS. Included in this receivable balance from DEFS at December 31, 2004, is a gas imbalance receivable of $0.9 million. At December 31, 2004 and 2003, we had a payable to DEFS of $22.4 million and $15.0 million, respectively, related to direct payroll, payroll related costs, management fees, and other operational related charges, including those for Jonah, Chaparral and Val Verde as described above. Included in this payable balance at December 31, 2004 and 2003, is a gas imbalance payable to DEFS of $3.2 million and $1.5 million, respectively.

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO (see Note 11. Partners' Capital and Distributions).

We contract with Bison Insurance Company Limited ("Bison"), a wholly owned subsidiary of Duke Energy, for a majority of our insurance coverage, including property, liability, auto and directors and officers insurance coverage. For the years ended December 31, 2004, 2003 and 2002, we incurred insurance expense related to premiums paid to Bison of $6.5 million, $5.9 million and $3.8 million, respectively. At December 31, 2004 and 2003, we had insurance reimbursement receivables due from Bison of $5.2 million and $4.2 million, respectively.

Interest of the General Partner in the Partnership

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. According to the Partnership Agreement, the Company receives incremental incentive cash distributions when cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target - $0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target - $0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target - Cash distributions greater than $0.45 per Unit	50%	50%

During the year ended December 31, 2004, distributions paid to the General Partner totaled $66.9 million, including incentive distributions of $63.5 million.

Interests of Duke Energy in the Partnership

In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs began participating in distributions of cash and allocations of profit and loss in a manner identical to our Units and are treated as Units for purposes of this Report. These Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. Pursuant to our Partnership Agreement, we have registered the resale by Duke Energy of these Units with the SEC. As of December 31, 2004, none of these Units had been sold by Duke Energy.

On February 24, 2005, our General Partner was acquired by EPCO, a privately held company controlled by Dan L. Duncan. Additionally, in a separate transaction, EPCO and its affiliates have agreed to purchase the 2.5 million Units from Duke Energy, valued at approximately $100.0 million (see Note 21. Subsequent Event).

Item 14. ***Principal Accounting Fees and Services***

The following table describes fees for professional audit services rendered by KPMG, our principal accountant, for the audit of our financial statements for the years ended December 31, 2004 and 2003, and for fees billed for other services rendered by KPMG during those periods (in thousands):

Type of Fee	Years Ended December 31, 2004	2003
Audit Fees (1)	$ 2,079	$ 953
Audit Related Fees (2)	21	58
Tax Fees (3)	88	183
All Other Fees (4)	—	656
Total	$ 2,188	$ 1,850

(1) Audit fees include fees for the audits of the consolidated financial statements as well as for the audit of internal control over financial reporting.

(2) Audit related fees consist principally of fees for audits of financial statements of certain employee benefit plans and certain internal control documentation assistance.

(3) Tax Fees consist of fees for sales and use tax consultation and tax compliance services.

(4) All Other Fees include the aggregate fees we paid during the year ended December 31, 2003, for products and services provided by KPMG, other than the services reported above. The majority of the other fees in 2003 are fees for litigation support services related to the D.R.D. legal proceedings which was settled on July 16, 2003 (see Note 16. Commitments and Contingencies).

Procedures for Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountant

Pursuant to its charter, the Audit Committee of our Board of Directors is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent registered public accountants. KPMG's engagement to conduct our audit was approved by the Audit Committee on April 26, 2004. Additionally, all permissible non-audit engagements with KPMG have been reviewed and approved by the Audit Committee, pursuant to pre-approval policies and procedures established by the Audit Committee.

PART IV

Item 15. *Exhibits, Financial Statement Schedules.*

(a) The following documents are filed as a part of this Report:

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this Report for financial statements filed as part of this Report.

(2) Financial Statement Schedules: None.

(3) Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).

3.2	Third Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated September 21, 2001 (Filed as Exhibit 3.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Indenture between TE Products Pipeline Company, Limited Partnership and The Bank of New York, as Trustee, dated as of January 27, 1998 (Filed as Exhibit 4.3 to TE Products Pipeline Company, Limited Partnership's Registration Statement on Form S-3 (Commission File No. 333-38473) and incorporated herein by reference).
4.3	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.4	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.6	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
4.7	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.1+	Duke Energy Corporation Executive Savings Plan (Filed as Exhibit 10.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.2+	Duke Energy Corporation Executive Cash Balance Plan (Filed as Exhibit 10.8 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.3+	Duke Energy Corporation Retirement Benefit Equalization Plan (Filed as Exhibit 10.9 to Form 10-K for TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).

10.4+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan executed on March 8, 1994 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1994 and incorporated herein by reference).
10.5+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan, Amendment 1, effective January 16, 1995 (Filed as Exhibit 10.12 to Form 10-Q of TEPPCO Partners,

	L.P. (Commission File No. 1-10403) for the quarter ended June 30, 1999 and incorporated herein by reference).
10.6+	Form of Employment Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth, John N. Goodpasture, Leonard W. Mallett, Stephen W. Russell, C. Bruce Shaffer, and Barbara A. Carroll (Filed as Exhibit 10.20 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
10.7	Services and Transportation Agreement between TE Products Pipeline Company, Limited Partnership and Fina Oil and Chemical Company, BASF Corporation and BASF Fina Petrochemical Limited Partnership, dated February 9, 1999 (Filed as Exhibit 10.22 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.8	Call Option Agreement, dated February 9, 1999 (Filed as Exhibit 10.23 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.9+	Form of Employment and Non-Compete Agreement between the Company and J. Michael Cockrell effective January 1, 1999 (Filed as Exhibit 10.29 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.10+	Texas Eastern Products Pipeline Company Non-employee Directors Unit Accumulation Plan, effective April 1, 1999 (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.11+	Texas Eastern Products Pipeline Company Non-employee Directors Deferred Compensation Plan, effective November 1, 1999 (Filed as Exhibit 10.31 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.12+	Texas Eastern Products Pipeline Company Phantom Unit Retention Plan, effective August 25, 1999 (Filed as Exhibit 10.32 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.13+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Amendment and Restatement, effective January 1, 2000 (Filed as Exhibit 10.28 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.14+	TEPPCO Supplemental Benefit Plan, effective April 1, 2000 (Filed as Exhibit 10.29 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.15+	Employment Agreement with Barry R. Pearl (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2001 and incorporated herein by reference).
10.16	Second Amended and Restated Agreement of Limited Partnership of TE Products Pipeline Company, Limited Partnership, dated September 21, 2001 (Filed as Exhibit 3.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.17	Amended and Restated Agreement of Limited Partnership of TCTM, L.P., dated September 21, 2001 (Filed as Exhibit 3.9 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.18	Contribution, Assignment and Amendment Agreement among TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., Texas Eastern Products Pipeline Company, LLC, and TEPPCO GP, Inc., dated July 26, 2001 (Filed as Exhibit 3.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2001 and incorporated herein by reference).

10.19	Certificate of Formation of TEPPCO Colorado, LLC (Filed as Exhibit 3.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1998 and incorporated herein by reference).
10.20	Agreement of Limited Partnership of TEPPCO Midstream Companies, L.P., dated September 24, 2001 (Filed as Exhibit 3.10 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2001 and incorporated herein by reference).
10.21	Agreement of Partnership of Jonah Gas Gathering Company dated June 20, 1996 as amended by that certain Assignment of Partnership Interests dated September 28, 2001 (Filed as Exhibit 10.40 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.22	Unanimous Written Consent of the Board of Directors of TEPPCO GP, Inc. dated February 13, 2002 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.23	Amended and Restated Credit Agreement among TEPPCO Partners, L.P. as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and Certain Lenders, as Lenders dated as of March 28, 2002 ($500,000,000 Revolving Facility) (Filed as Exhibit 10.45 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the three months ended March 31, 2002 and incorporated herein by reference).
10.24	Purchase and Sale Agreement between Burlington Resources Gathering Inc. as Seller and TEPPCO Partners, L.P., as Buyer, dated May 24, 2002 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.25	Amendment, dated as of June 27, 2002 to the Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent, and Certain Lenders, dated as of March 28, 2002 ($500,000,000

	Revolving Credit Facility) (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.26	Agreement of Limited Partnership of Val Verde Gas Gathering Company, L.P., dated May 29, 2002 (Filed as Exhibit 10.48 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.27+	Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan, effective June 1, 2002 (Filed as Exhibit 10.43 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.28+	Amended and Restated TEPPCO Supplemental Benefit Plan, effective November 1, 2002 (Filed as Exhibit 10.44 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.29+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Second Amendment and Restatement, effective January 1, 2003 (Filed as Exhibit 10.45 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.30+	Amended and Restated Texas Eastern Products Pipeline Company, LLC Management Incentive Compensation Plan, effective January 1, 2003 (Filed as Exhibit 10.46 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.31+	Amended and Restated TEPPCO Retirement Cash Balance Plan, effective January 1, 2002 (Filed as Exhibit 10.47 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.32	Formation Agreement between Panhandle Eastern Pipe Line Company and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, dated as of August 10, 2000 (Filed as Exhibit 10.48 to Form 10-K of TEPPCO Partners, L.P.

	(Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.33	Amended and Restated Limited Liability Company Agreement of Centennial Pipeline LLC dated as of August 10, 2000 (Filed as Exhibit 10.49 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.34	Guaranty Agreement, dated as of September 27, 2002, between TE Products Pipeline Company, Limited Partnership and Marathon Ashland Petroleum LLC for Note Agreements of Centennial Pipeline LLC (Filed as Exhibit 10.50 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.35	LLC Membership Interest Purchase Agreement By and Between CMS Panhandle Holdings, LLC, As Seller and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, Severally as Buyers, dated February 10, 2003 (Filed as Exhibit 10.51 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.36	Joint Development Agreement between TE Products Pipeline Company, Limited Partnership and Louis Dreyfus Plastics Corporation dated February 10, 2000 (Filed as Exhibit 10.52 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2003 and incorporated herein by reference).
10.37	Credit Agreement among TEPPCO Partners, L.P. as Borrower, SunTrust Bank as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders, dated as of June 27, 2003 ($550,000,000 Revolving Facility) (Filed as Exhibit 10.52 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2003 and incorporated herein by reference).
10.38	Agreement of Limited Partnership of Mont Belvieu Storage Partners, L.P. dated effective January 21, 2003 (Filed as Exhibit 10.53 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2003 and incorporated herein by reference).
10.39	Letter of Agreement Clarifying Rights and Obligations of the Parties Under the Mont Belvieu Storage Partners, L.P., Partnership Agreement and the Mont Belvieu Venture, LLC, LLC Agreement, dated October 13, 2003 (Filed as Exhibit 10.54 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2003 and incorporated herein by reference).
10.40	Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders dated as of October 21, 2004 ($600,000,000 Revolving Facility) (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of October 21, 2004 and incorporated herein by reference).
10.41+*	Texas Eastern Products Pipeline Company Amended and Restated Non-employee Directors Deferred Compensation Plan, effective April 1, 2002.
10.42+*	Texas Eastern Products Pipeline Company Second Amended and Restated Non-employee Directors Unit Accumulation Plan, effective January 1, 2004.
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
21	Subsidiaries of the Partnership (Filed as Exhibit 21 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
23*	Consent of KPMG LLP.
24*	Powers of Attorney.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.
\+ A management contract or compensation plan or arrangement.

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.

TEPPCO Partners, L.P.
(Registrant)
(A Delaware Limited Partnership)

By: Texas Eastern Products Pipeline Company, LLC, as General Partner

By: /s/ BARRY R. PEARL
Barry R. Pearl,
President and Chief Executive Officer

By: /s/ CHARLES H. LEONARD
Charles H. Leonard,
Senior Vice President and Chief Financial Officer

Dated: March 1, 2005

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

Signature	Title	Date
BARRY R. PEARL* Barry R. Pearl	President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
CHARLES H. LEONARD Charles H. Leonard	Senior Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC (Principal Accounting and Financial Officer)	March 1, 2005
JIM W. MOGG* Jim W. Mogg	Chairman of the Board of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
MARK A. BORER * Mark A. Borer	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
MICHAEL J. BRADLEY* Michael J. Bradley	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
MILTON CARROLL* Milton Carroll	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
DERRILL CODY* Derrill Cody	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
JOHN P. DESBARRES* John P. DesBarres	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
WILLIAM H. EASTER III* William H. Easter III	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005
PAUL F. FERGUSON, JR.* Paul F. Ferguson, Jr.	Director of Texas Eastern Products Pipeline Company, LLC	March 1, 2005

* Signed on behalf of the Registrant and each of these persons:

By: /s/ CHARLES H. LEONARD
(Charles H. Leonard, Attorney-in-Fact)

CONSOLIDATED FINANCIAL STATEMENTS
OF TEPPCO PARTNERS, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Financial Statements:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
TEPPCO Partners, L.P.:

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

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

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of TEPPCO Partners, L.P.'s internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2005, expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
February 24, 2005

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16,422	$ 29,469

Accounts receivable, trade (net of allowance for doubtful accounts of $112 and $4,700)	553,628	371,938
Accounts receivable, related parties	12,921	3,143
Inventories	19,521	16,060
Other	42,138	32,208
Total current assets	644,630	452,818
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $407,670 and $345,357)	1,703,702	1,619,163
Equity investments	373,652	365,286
Intangible assets	407,358	438,565
Goodwill	16,944	16,944
Other assets	51,419	48,216
Total assets	$ 3,197,705	$ 2,940,992
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 564,464	$ 357,852
Accounts payable, related parties	25,730	21,486
Accrued interest	32,292	35,111
Other accrued taxes	13,309	9,941
Other	46,593	51,201
Total current liabilities	682,388	475,591
Senior Notes	1,127,226	1,129,650
Other long-term debt	353,000	210,000
Other liabilities and deferred credits	13,643	16,430
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive loss	—	(2,902)
General partner's interest	(33,006)	(7,181)
Limited partners' interests	1,054,454	1,119,404
Total partners' capital	1,021,448	1,109,321
Total liabilities and partners' capital	$ 3,197,705	$ 2,940,992

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per Unit amounts)

	Years Ended December 31, 2004	2003	2002
Operating revenues:			
Sales of petroleum products	$ 5,434,127	$ 3,766,651	$ 2,823,800
Transportation – Refined products	148,166	138,926	123,476
Transportation – LPGs	87,050	91,787	74,577
Transportation – Crude oil	37,177	29,057	27,414
Transportation – NGLs	41,204	39,837	38,870
Gathering – Natural gas	140,122	135,144	90,053
Mont Belvieu operations	—	—	15,238
Other	70,346	54,430	48,735
Total operating revenues	5,958,192	4,255,832	3,242,163
Costs and expenses:			
Purchases of petroleum products	5,372,971	3,711,207	2,772,328
Operating, general and administrative	223,382	201,329	158,753
Operating fuel and power	45,404	38,511	36,814
Depreciation and amortization	112,894	100,728	86,032
Taxes – other than income taxes	17,461	15,597	17,989
Gains on sales of assets	(1,053)	(3,948)	—
Total costs and expenses	5,771,059	4,063,424	3,071,916
Operating income	187,133	192,408	170,247
Interest expense – net	(72,053)	(84,250)	(66,192)
Equity earnings	25,981	16,863	11,980
Other income – net	1,320	748	1,827
Net income	$ 142,381	$ 125,769	$ 117,862
Net Income Allocation:			

	2004	2003	2002
Limited Partner Unitholders	$ 101,307	$ 89,191	$ 81,238
Class B Unitholder	—	1,806	6,943
General Partner	41,074	34,772	29,681
Total net income allocated	$ 142,381	$ 125,769	$ 117,862
Basic and diluted net income per Limited Partner and Class B Unit	$ 1.61	$ 1.52	$ 1.79
Weighted average Limited Partner and Class B Units outstanding	62,999	59,765	49,202

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31, 2004	2003	2002
Cash flows from operating activities:			
Net income	$ 142,381	$ 125,769	$ 117,862
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	112,894	100,728	86,032
Earnings in equity investments, net of distributions	21,232	11,140	18,401
Gains on sales of assets	(1,053)	(3,948)	—
Non-cash portion of interest expense	(391)	4,793	4,916
Increase in accounts receivable	(181,690)	(100,085)	(50,313)
Decrease (increase) in inventories	(3,461)	(956)	2,139
Increase in other current assets	(9,926)	(953)	(16,263)
Increase in accounts payable and accrued expenses	186,942	95,540	68,805
Other	(718)	7,326	3,338
Net cash provided by operating activities	266,210	239,354	234,917
Cash flows from investing activities:			
Proceeds from sales of assets	1,226	8,531	3,380
Proceeds from cash investments	—	750	—
Purchase of assets	(3,421)	(27,469)	—
Purchase of Val Verde Gathering System	—	—	(444,150)
Purchase of Jonah Gas Gathering Company	—	—	(7,319)
Purchase of Chaparral NGL System	—	—	(132,372)
Investment in Mont Belvieu Storage Partners, L.P.	(21,358)	(2,533)	—
Investment in Centennial Pipeline LLC	(1,500)	(4,000)	(10,882)
Acquisition of additional interest in Centennial Pipeline LLC	—	(20,000)	—
Capital expenditures	(164,147)	(140,517)	(133,372)
Net cash used in investing activities	(189,200)	(185,238)	(724,715)
Cash flows from financing activities:			
Proceeds from revolving credit facilities	324,200	382,000	675,000
Issuance of Limited Partner Units, net	—	287,506	372,506
Issuance of Senior Notes	—	198,570	497,805
Proceeds from termination of interest rate swaps	—	—	44,896
Repayments on revolving credit facilities	(181,200)	(604,000)	(943,659)
Repurchase and retirement of Class B Units	—	(113,814)	—
Debt issuance costs	—	(3,381)	(7,025)
General Partner’s contributions	—	2	7,617
Distributions paid	(233,057)	(202,498)	(151,853)
Net cash (used in) provided by financing activities	(90,057)	(55,615)	495,287
Net increase (decrease) in cash and cash equivalents	(13,047)	(1,499)	5,489
Cash and cash equivalents at beginning of period	29,469	30,968	25,479
Cash and cash equivalents at end of period	$ 16,422	$ 29,469	$ 30,968
Non-cash investing activities:			
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ —	$ 61,042	$ —
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 77,510	$ 79,930	$ 48,908

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(in thousands, except Unit amounts)

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Loss	Total
Partners' capital at December 31, 2001	40,450,000	$ 13,190	$ 550,315	$ (20,324)	$ 543,181
Capital contributions	—	7,568	—	—	7,568
Issuance of Limited Partner Units, net	13,260,000	—	370,108	—	370,108
Net income on cash flow hedge	—	—	—	269	269
2002 net income allocation	—	29,681	81,238	—	110,919
2002 cash distributions	—	(37,718)	(104,932)	—	(142,650)
Issuance of Limited Partners Units upon exercise of options	99,597	49	2,398	—	2,447
Partners' capital at December 31, 2002	53,809,597	12,770	899,127	(20,055)	891,842
Issuance of Limited Partner Units, net	9,101,650	—	285,461	—	285,461
Retirement of Class B units	—	—	(10,993)	—	(10,993)
Net income on cash flow hedge	—	—	—	16,164	16,164
Reclassification due to discontinued portion of cash flow hedge	—	—	—	989	989
2003 net income allocation	—	34,772	89,191	—	123,963
2003 cash distributions	—	(54,725)	(145,427)	—	(200,152)
Issuance of Limited Partner Units upon exercise of options	87,307	2	2,045	—	2,047
Partners' capital at December 31, 2003	62,998,554	(7,181)	1,119,404	(2,902)	1,109,321
Adjustments to issuance of Limited Partner Units, net	—	—	(99)	—	(99)
Net income on cash flow hedge	—	—	—	2,902	2,902
2004 net income allocation	—	41,074	101,307	—	142,381
2004 cash distributions	—	(66,899)	(166,158)	—	(233,057)
Partners' capital at December 31, 2004	62,998,554	$ (33,006)	$ 1,054,454	$ —	$ 1,021,448

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. PARTNERSHIP ORGANIZATION

TEPPCO Partners, L.P. (the "Partnership"), a Delaware limited partnership, is a master limited partnership formed in March 1990. We operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L.P. ("TCTM") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"). Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships." Texas Eastern Products Pipeline Company, LLC (the "Company" or "General Partner"), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. The General Partner is an indirect wholly owned subsidiary of Duke Energy Field Services, LLC ("DEFS"), a joint venture between Duke Energy Corporation ("Duke Energy") and ConocoPhillips. Duke Energy holds an interest of approximately 70% in DEFS, and ConocoPhillips holds the remaining interest of approximately 30%. The Company, as general partner, performs all management and operating functions required for us, except for the management and operations of certain of the TEPPCO Midstream assets that are managed by DEFS on our behalf. We reimburse the General Partner for all reasonable direct and indirect expenses incurred in managing us.

As used in this Report, "we," "us," "our," and the "Partnership" means TEPPCO Partners, L.P. and, where the context requires, includes our subsidiaries.

On July 26, 2001, the Company restructured its general partner ownership of the Operating Partnerships to cause them to be indirectly wholly owned by us. TEPPCO GP, Inc. ("TEPPCO GP"), our subsidiary, succeeded the Company as general partner of the Operating Partnerships. All remaining partner interests in the Operating Partnerships not already owned by us were transferred to us. In exchange for this contribution, the Company's interest as our general partner was increased to 2%. The increased percentage is the economic equivalent of the aggregate interest that the Company had prior to the restructuring through its combined interests in us and the Operating Partnerships. As a result, we hold a 99.999% limited partner interest in the Operating Partnerships and TEPPCO GP holds a 0.001% general partner interest. This reorganization was undertaken to simplify required financial reporting by the Operating Partnerships when the Operating Partnerships issue guarantees of our debt.

At formation in 1990, we completed an initial public offering of 26,500,000 Units representing Limited Partner Interests ("Limited Partner Units") at $10.00 per Unit. In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs began participating in distributions of cash and allocations of profit and loss in a manner identical to Limited Partner Units and are treated as Limited Partner Units for purposes of this Report. These Limited Partner Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. Pursuant to our Partnership Agreement, we have registered the resale by Duke Energy of such Limited Partner Units with the Securities and Exchange Commission. As of December 31, 2004, none of these Limited Partner Units had been sold by Duke Energy.

At December 31, 2004 and 2003, we had outstanding 62,998,554 Limited Partner Units. At December 31, 2002, we had outstanding 3,916,547 Class B Limited Partner Units ("Class B Units"), which were issued to Duke Energy Transport and Trading Company, LLC ("DETTCO") in connection with an acquisition of assets initially acquired in 1998. On April 2, 2003, we repurchased and retired all of the 3,916,547 previously outstanding Class B Units with proceeds from the issuance of additional Limited Partner Units (see Note 11. Partners' Capital and Distributions). Collectively, the Limited Partner Units and Class B Units are referred to as "Units."

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We adhere to the following significant accounting policies in the preparation of our consolidated financial statements.

Basis of Presentation and Principles of Consolidation

The financial statements include our accounts on a consolidated basis. We have eliminated all significant intercompany items in consolidation. We have reclassified certain amounts from prior periods to conform with the current presentation.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires our management to make estimates and assumptions that affect the 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 periods. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Business Segments

We operate and report in three business segments: transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies.

Our interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC"). We refer to refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas in this Report, collectively, as "petroleum products" or "products."

Revenue Recognition

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Terminaling revenues are recognized as products are out-loaded. Revenues from the sale of product inventory are recognized when the products are sold.

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil, and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas. Revenues are accrued at the time title to the product sold transfers to the purchaser, which typically occurs upon receipt of the product by the purchaser, and purchases are accrued at the time title to the product purchased transfers to our crude oil marketing company, TEPPCO Crude Oil, L.P. ("TCO"), which typically occurs upon our receipt of the product. Revenues related to trade documentation and pumpover fees are recognized as services are completed.

Except for crude oil purchased from time to time as inventory, our policy is to purchase only crude oil for which we have a market to sell and to structure sales contracts so that crude oil price fluctuations do not materially affect the margin received. As we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users or by entering into a future delivery obligation. Through these transactions, we seek to maintain a position that is balanced between crude oil purchases and sales and future delivery obligations. However, certain basis risks (the risk that price relationships between delivery points, classes of products or delivery periods will change) cannot be completely hedged.

Our Midstream Segment revenues are earned from the gathering of natural gas, fractionation of NGLs and transportation of NGLs. Gathering and transportation revenues are recognized as natural gas or NGLs are delivered to customers. Revenues are also earned from the sale of condensate liquid extracted from the natural gas stream to an Upstream Segment marketing affiliate. Fractionation revenues are recognized ratably over the contract year as products are delivered to DEFS. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances discussed in "Natural Gas Imbalances." Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximate fair value because of the short term nature of these investments.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Balance at beginning of period	$ 4,700	$ 4,608	$ 4,422
Charges to expense	536	793	325
Deductions and other	(5,124)	(701)	(139)
Balance at end of period	$ 112	$ 4,700	$ 4,608

Inventories

Inventories consist primarily of petroleum products and crude oil, which are valued at the lower of cost (weighted average cost method) or market. Our Downstream Segment acquires and disposes of various products under exchange agreements. Receivables and payables arising from these transactions are usually satisfied with products rather than cash. The net balances of exchange receivables and payables are valued at weighted average cost and included in inventories. Inventories of materials and supplies, used for ongoing replacements and expansions, are carried at the lower of fair value or cost.

Property, Plant and Equipment

We record property, plant and equipment at its acquisition cost. Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance

expense. Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum).

We evaluate impairment of long-lived assets in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

Asset Retirement Obligations

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which we incur a legal obligation for the retirement of tangible long-lived assets. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement of the asset retirement obligation, the liability will be adjusted at the end of each reporting period to reflect changes in the estimated future cash flows underlying the obligation. Determination of any amounts recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates.

The Downstream Segment assets consist primarily of an interstate trunk pipeline system and a series of storage facilities that originate along the upper Texas Gulf Coast and extend through the Midwest and northeastern United States. We transport refined products, LPGs and petrochemicals through the pipeline system. These products are primarily received in the south end of the system and stored and/or transported to various points along the system per customer nominations. The Upstream Segment's operations include purchasing crude oil from producers at the wellhead and providing delivery, storage and other services to its customers. The properties in the Upstream Segment consist of interstate trunk pipelines, pump stations, trucking facilities, storage tanks and various gathering systems primarily in Texas and Oklahoma. The Midstream Segment gathers natural gas from wells owned by producers and transports natural gas and NGLs on its pipeline systems, primarily in Texas, Wyoming, New Mexico and Colorado. The Midstream Segment also owns and operates two NGL fractionator facilities in Colorado.

We have completed our assessment of SFAS 143, and we have determined that we are obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of our assets. However, we are not able to reasonably determine the fair value of the asset retirement obligations for our trunk, interstate and gathering pipelines and our surface facilities, since future dismantlement and removal dates are indeterminate.

In order to determine a removal date for our gathering lines and related surface assets, reserve information regarding the production life of the specific field is required. As a transporter and gatherer of crude oil and natural gas, we are not a producer of the field reserves, and we therefore do not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which we gather crude oil and natural gas. In the absence of such information, we are not able to make a reasonable estimate of when future dismantlement and removal dates of our gathering assets will occur. With regard to our trunk and interstate pipelines and their related surface assets, it is impossible to predict when demand for transportation of the related products will cease. Our right-of-way agreements allow us to maintain the right-of-way rather than remove the pipe. In addition, we can evaluate our trunk pipelines for alternative uses, which can be and have been found.

We will record such asset retirement obligations in the period in which more information becomes available for us to reasonably estimate the settlement dates of the retirement obligations. The adoption of SFAS 143 did not have an effect on our financial position, results of operations or cash flows.

Capitalization of Interest

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 5.74%, 6.50% and 5.11% for the years ended December 31, 2004, 2003 and 2002, respectively. During the years ended December 31, 2004, 2003 and 2002, the amount of interest capitalized was $4.2 million, $5.3 million and $4.3 million, respectively.

Intangible Assets

Intangible assets at December 31, 2004, consist primarily of gathering contracts assumed in the acquisition of Jonah Gas Gathering System ("Jonah") on September 30, 2001, and the acquisition of Val Verde Gathering System ("Val Verde") on June 30, 2002, the fractionation agreement with DEFS and other intangible assets (see Note 3. Goodwill and Other Intangible Assets).

In connection with the acquisitions of Jonah and Val Verde, we assumed contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming, and we assumed fixed-term contracts with customers that gather coal bed methane ("CBM") from the San Juan Basin in New Mexico and Colorado, respectively (see Note 5. Acquisitions and Dispositions). The value assigned to these intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production to the gathering system. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 3. Goodwill and Other Intangible Assets).

In connection with the purchase of the fractionation facilities in 1998, we entered into a fractionation agreement with DEFS. The fractionation agreement is being amortized over a period of 20 years, which is the term of the agreement with DEFS (see Note 7. Related Party Transactions).

In connection with the acquisition of crude supply and transportation assets in November 2003, we acquired intangible customer contracts for $8.7 million, which are amortized on a unit-of-production basis (see Note 5. Acquisitions and Dispositions).

We have $33.4 million of excess investment in our equity investment in Centennial Pipeline LLC, which was created upon formation of the company. The excess investment is included in our equity investments account. This excess investment is accounted for as an intangible asset with an indefinite life. We assess the intangible asset for impairment on an annual basis (see Note 3. Goodwill and Other Intangible Assets).

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001 (see Note 3. Goodwill and Other Intangible Assets). SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually. SFAS 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives. Beginning January 1, 2002, effective with the adoption of SFAS 142, we no longer record amortization expense related to goodwill or amortization

expense related to the excess investment on our equity investment in Seaway Crude Pipeline Company (equity method goodwill).

Environmental Expenditures

We accrue for environmental costs that relate to existing conditions caused by past operations. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations.

The following table presents the activity of our environmental reserve for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Balance at beginning of period	$ 7,639	$ 7,693	$ 6,434
Charges to expense	5,178	6,824	5,785
Deductions and other	(7,780)	(6,878)	(4,526)
Balance at end of period	$ 5,037	$ 7,639	$ 7,693

Natural Gas Imbalances

Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas gathering volumes to our gathering systems than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. If the customers supply more natural gas gathering volumes than they nominated, Val Verde and Jonah record a payable for the amount due to customers and also record a receivable for the same amount due from connecting pipeline transporters or shippers. If the customers supply less natural gas gathering volumes than they nominated, Val Verde and Jonah record a receivable reflecting the amount due from customers and a payable for the same amount due to connecting pipeline transporters or shippers. We record natural gas imbalances using a mark-to-market approach.

Income Taxes

We are a limited partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statements of income, is includable in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for our operations. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholders' tax attributes in the Partnership.

Use of Derivatives

We account for derivative financial instruments in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, *an amendment of FASB Statement No. 133.* These statements establish accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet at fair value as either assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative.

Our derivative instruments consist primarily of interest rate swaps and contracts for the purchase and sale of petroleum products in connection with our crude oil marketing activities. Substantially all derivative instruments related to our crude oil marketing activities meet the normal purchases and sales criteria of SFAS 133, as amended, and as such, changes in the fair value of petroleum product purchase and sales agreements are reported on the accrual basis of accounting. SFAS 133 describes normal purchases and sales as contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

For all hedging relationships, we formally document at inception the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the item, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed and a description of the method of measuring ineffectiveness. This process includes linking all derivatives that are designated as fair value or cash flow to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. If it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

For derivative instruments designated as fair value hedges, gains and losses on the derivative instrument are offset against related results on the hedged item in the statement of income. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a fair value hedge, along with the loss or gain on the hedged asset or liability or unrecognized firm commitment of the hedged item that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective as a hedge, until earnings are affected by the variability in cash flows of the designated hedged item. Hedge effectiveness is measured at least quarterly based on the relative cumulative changes in fair value between the derivative contract and the hedged item over time. The ineffective portion of the change in fair value of a derivative instrument that qualifies as either a fair value hedge or a cash flow hedge is reported immediately in earnings.

According to SFAS 133, as amended, we are required to discontinue hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the fair value or cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised, the derivative is de-designated as a hedging instrument, because it is unlikely that a forecasted transaction will occur, a hedged firm commitment no longer meets the definition of a firm commitment, or management determines that designation of the derivative as a hedging instrument is no longer appropriate.

When hedge accounting is discontinued because it is determined that the derivative no longer qualifies as an effective fair value hedge, we continue to carry the derivative on the balance sheet at its fair value and no longer adjust the hedged asset or liability for changes in fair value. The adjustment of the carrying amount of the hedged asset or liability is accounted for in the same manner as other components of the carrying amount of that asset or

liability. When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, we continue to carry the derivative on the balance sheet at its fair value, remove any asset or liability that was recorded pursuant to recognition of the firm commitment from the balance sheet, and recognize any gain or loss in earnings. When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, we continue to carry the derivative on the balance sheet at its fair value with subsequent changes in fair value included in earnings, and gains and losses that were accumulated in other comprehensive income are recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature. The fair values of these financial instruments are represented in our consolidated balance sheets.

Net Income Per Unit

Basic net income per Unit is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 63.0 million Units, 59.8 million Units and 49.2 million Units for the years ended December 31, 2004, 2003 and 2002, respectively). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each year (see Note 11. Partner's Capital and Distributions). The General Partner was allocated $41.1 million (representing 28.85%) of net income for the year ended December 31, 2004, $34.8 million (representing 27.65%) of net income for the year ended December 31, 2003, and $29.7 million (representing 25.18%) of net income for the year ended December 31, 2002. The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our Limited Partnership Agreement.

Diluted net income per Unit is similar to the computation of basic net income per Unit discussed above, except that the denominator is increased to include the dilutive effect of outstanding Unit options by application of the treasury stock method. For the years ended December 31, 2003 and 2002, the denominator was increased by 11,878 Units and 32,053 Units, respectively. For the year ended December 31, 2004, diluted net income per Unit equaled basic net income per Unit as the denominator was not changed because all remaining outstanding Unit options were exercised during the third quarter of 2003 (see Note 13. Unit-Based Compensation).

Unit Option Plan

We have not granted options for any periods presented. For options outstanding under the 1994 Long Term Incentive Plan (see Note 13. Unit-Based Compensation), we followed the intrinsic value method of accounting for recognizing stock-based compensation expense. Under this method, we record no compensation expense for Unit options granted when the exercise price of the options granted is equal to, or greater than, the market price of our Units on the date of the grant. During the year ended December 31, 2003, all remaining outstanding Unit options were exercised.

In December 2002, SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* was issued. SFAS 148 amends SFAS No. 123, *Accounting for Stock-Based Compensation*, and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002, and are included in Note 13. Unit-Based Compensation.

Assuming we had used the fair value method of accounting for our Unit option plan, pro forma net income for the year ended December 31, 2002, would be lower than reported net income by an immaterial amount. Pro forma net income would equal reported net income for the years ended December 31, 2004 and 2003. Pro forma net income per Unit would equal reported net income per Unit for the periods presented. The adoption of SFAS 148 did not have an effect on our financial position, results of operations or cash flows.

New Accounting Pronouncements

In December 2003, the FASB revised FASB Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* ("FIN 46"). FIN 46, issued by the FASB in January 2003, requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The revised statement, FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* ("FIN 46(R)"), clarifies some of the requirements of FIN 46, eases some implementation problems that companies experienced implementing FIN 46, adds new scope exceptions and makes the probability more likely for many companies that potential variable interest entities will be identified and consolidated. We adopted the new requirements detailed in FIN 46(R) as of March 31, 2004. In connection with our adoption of FIN 46(R), we evaluated our investments in Centennial Pipeline LLC, Seaway Crude Pipeline Company and Mont Belvieu Storage Partners, L.P. and determined that these entities are not materially affected by our adoption of FIN 46(R), and thus we have accounted for them as equity method investments (see Note 6. Equity Investments). Our adoption of FIN 46(R) did not have an effect on our financial position, results of operations or cash flows.

On December 8, 2003, President Bush signed into law a bill that expands Medicare, primarily adding a prescription drug benefit for Medicare-eligible retirees starting in 2006. We anticipate that the benefits we pay after 2006 could be lower as a result of the new Medicare provisions; however, at this time the retiree medical obligations and costs reported do not reflect any changes as a result of this legislation. Deferring the recognition of the new Medicare provisions' impact was permitted by FASB Staff Position ("FSP") Nos. 106-1 and 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*, due to open questions about some of the new Medicare provisions and a lack of authoritative accounting guidance about certain matters. The final accounting guidance could require changes to previously reported information. We adopted the provisions of these FSPs in the quarter ended September 30, 2004. This regulation did not have a material adverse effect on our financial position, results of operations or cash flows.

In December 2003, the FASB issued a revision SFAS No. 132, *Employers' Disclosures about Pensions and Other Post-Retirement Benefits*. This revision required that companies provide more details about their plan assets, benefit obligations, cash flows, benefit costs and other relevant information. A description of investment policies and strategies and target allocation percentages, or target ranges, for these asset categories also is required in financial statements. Cash flows will include projections of future benefit payments and an estimate of contributions to be made in the next year to fund pension and other postretirement benefit plans. In addition to expanded annual disclosures, the FASB is requiring companies to report the various elements of pension and other postretirement benefit costs on a quarterly basis. The guidance is effective for fiscal years ending after December 15, 2003, and for quarters beginning after December 15, 2003. We adopted the provisions of the revised SFAS 132 effective December 31, 2003, and certain provisions regarding disclosure of information about estimated future benefit payments in the first quarter of 2004.

In April 2004, the Emerging Issues Task Force ("EITF") reached consensus in EITF 03-06, *Participating Securities and the Two-Class Method under FASB Statement No. 128*, to clarify what is meant by a participating security as described in SFAS No. 128, *Earnings Per Share.* The consensus also provides guidance on applying the two-class method for computing earnings per share. The two-class method is an earnings allocation formula for computing earnings per share and is the required method prescribed by SFAS 128 for companies with participating

securities or more than one class of common stock. The consensus primarily affects companies that issue securities that are entitled to participate in dividends with common shares and would cause affected companies to report lower earnings per share amounts. The consensus is to be applied retroactively for periods beginning after March 31, 2004. The adoption of EITF 03-06 did not have an effect on our financial position, results of operations or cash flows.

In July 2004, the EITF reached consensus in EITF 02-14, *Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock*, to clarify whether Accounting Principles Board ("APB") Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock* applies to joint ventures with ownership not represented by common stock. APB Opinion No. 18 scopes out investments with ownership not represented by common stock. EITF 02-14 clarifies that joint ventures with ownership represented by in-substance common stock, as defined by EITF 02-14, are subject to the requirements of APB Opinion No. 18. We do not have common stock ownership in our three joint ventures, Centennial Pipeline LLC, Seaway Crude Pipeline Company and Mont Belvieu Storage Partners, L.P. We have assessed the impact of EITF 02-14 on these three joint ventures and have determined that we have in-substance common stock ownership for all of these ventures. However, similar to other companies with ownership structures in joint ventures not represented by common stock, we have historically accounted for these joint ventures under the guidance of APB Opinion No. 18 due to a lack of other authoritative guidance. The consensuses in this EITF should be applied in reporting periods beginning after September 15, 2004. The adoption of EITF 02-14 did not have an effect on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment*. SFAS 123(R) requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of the compensation cost is to be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards are to be re-measured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) is a revision of SFAS 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) is effective for public companies as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. All public companies that adopted the fair-value-based method of accounting must use the modified prospective transition method and may elect to use the modified retrospective transition method. We do not believe that the adoption of SFAS 123(R) will have a material effect on our financial position, results of operations, or cash flows.

NOTE 3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually.

To perform an impairment test of goodwill, we have identified our reporting units and have determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units. We then determine the fair value of each reporting unit and compare it to the carrying value of the reporting unit. We will continue to compare the fair value of each reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There has been no goodwill impairment losses recorded since the adoption of SFAS 142.

At December 31, 2004 and 2003, we have $16.9 million of unamortized goodwill and $25.5 million of excess investment in our equity investment in Seaway Crude Pipeline Company (equity method goodwill). The excess investment is included in our equity investments account at December 31, 2004. The following table presents the carrying amount of goodwill and equity method goodwill at December 31, 2004 and 2003, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill	$ —	$ 2,777	$ 14,167	$ 16,944
Equity method goodwill	—	—	25,502	25,502

Other Intangible Assets

The following table reflects the components of intangible assets being amortized at December 31, 2004 and 2003 (in thousands):

	December 31, 2004		December 31, 2003	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets being amortized:				
Gathering and transportation agreements	$ 464,337	$ (91,262)	$ 464,337	$ (62,436)
Fractionation agreement	38,000	(12,825)	38,000	(10,925)
Other	12,262	(3,154)	11,270	(1,681)
Total	$ 514,599	$ (107,241)	$ 513,607	$ (75,042)

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $32.2 million, $36.2 million and $27.9 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The value assigned to our intangible assets for natural gas gathering contracts is amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. We update throughput estimates and evaluate the remaining expected useful lives of the contract assets on a quarterly basis based on the best available information. Due to expansions on the gathering systems at Jonah and because of certain limited production forecasts obtained from some of the producers on the Jonah system related to the expansions, in the second quarter of 2003 we increased our best estimate of future throughput on the Jonah system. This increase in the estimate of future throughput extended the amortization period of Jonah's natural gas gathering contracts by an estimated 9 years, increasing from approximately 16 years to approximately 25 years. During the fourth quarter of 2004, additional limited production forecasts were obtained from some of the producers on the Jonah system related to future expansions of the system, and as a result, we again increased our best estimate of future throughput on the Jonah system. This increase in the estimate of future throughput extended the amortization period of Jonah's natural gas gathering contracts by an estimated 10 years, increasing from approximately 25 years to approximately 35 years. Revisions to these estimates may occur as additional production information is made available to us.

The amortization of the contracts related to the Val Verde assets is also amortized on a unit-of-production basis. During the fourth quarter of 2004, certain limited production forecasts were obtained from some of the producers on the Val Verde system, and as a result, the amortization period of Val Verde's natural gas gathering contracts was extended by approximately 10 years, from approximately 20 years to approximately 30 years. Revisions to these estimates may occur as additional production information is made available to us.

The values assigned to our fractionation agreement and other intangible assets are generally amortized on a straight-line basis. Our fractionation agreement with DEFS is being amortized over its contract period of 20 years. The amortization periods for our other intangible assets, which include non-compete and other agreements, range from 3 years to 15 years. In connection with the acquisition of crude supply and transportation assets in November 2003, we acquired intangible customer contracts for $8.7 million, which are being amortized on a unit-of-production basis (see Note 5. Acquisitions and Dispositions).

At December 31, 2004, we have $33.4 million of excess investment in our equity investment in Centennial Pipeline LLC, which was created upon formation of the company. The excess investment is included in our equity investments account at December 31, 2004. This excess investment is accounted for as an intangible asset with an indefinite life. We assess the intangible asset for impairment on an annual basis.

The following table sets forth the estimated amortization expense of intangible assets for the years ending December 31 (in thousands):

2005	$ 29,679
2006	31,952
2007	32,305
2008	31,144
2009	29,091

NOTE 4. INTEREST RATE SWAPS

In July 2000, we entered into an interest rate swap agreement to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. This interest rate swap matured in April 2004. We designated this swap agreement, which hedged exposure to variability in expected future cash flows attributed to changes in interest rates, as a cash flow hedge. The swap agreement was based on a notional amount of $250.0 million. Under the swap agreement, we paid a fixed rate of interest of 6.955% and received a floating rate based on a three-month U.S. Dollar LIBOR rate. Because this swap was designated as a cash flow hedge, the changes in fair value, to the extent the swap was effective, were recognized in other comprehensive income until the hedged interest costs were recognized in earnings. In June 2003, we repaid the amounts outstanding under our revolving credit facility with borrowings under a new three year revolving credit facility and canceled the old facility (see Note 10. Debt). We redesignated this interest rate swap as a hedge of our exposure to increases in the benchmark interest rate underlying the new variable rate revolving credit facility. During the years ended December 31, 2004, 2003 and 2002, we recognized increases in interest expense of $2.9 million, $14.4 million and $12.9 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap.

During 2003, we determined that we would repay a portion of the amount outstanding under the revolving credit facility with proceeds from our Unit offering in August 2003 (see Note 11. Partners' Capital and Distributions) resulting in a reduction of probable future interest payments under the credit facility. We reduced the outstanding balance of the revolving credit facility at December 31, 2003, to $210.0 million. During the year ended December 31, 2003, we recognized a loss of $1.0 million for the portion of the discontinued hedge. The total fair value of the interest rate swap was a loss of approximately $3.9 million at December 31, 2003. The remaining $2.9 million of other comprehensive income was transferred to earnings during the period from January 1, 2004, through the maturity of the interest rate swap in April 2004.

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the

principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51%. During the years ended December 31, 2004, 2003 and 2002, we recognized reductions in interest expense of $9.6 million, $10.0 million and $8.6 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the quarter ended December 31, 2004, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized. The fair value of this interest rate swap was a gain of approximately $3.4 million at December 31, 2004, and a gain of approximately $2.3 million at December 31, 2003.

In February 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7.625% Senior Notes due 2012. The swap agreements had a combined notional amount of $500.0 million and matured in 2012 to match the principal and maturity of the Senior Notes. Under the swap agreements, we paid a floating rate of interest based on a U.S. Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7.625%. In July 2002, the swap agreements were terminated resulting in a gain of approximately $18.0 million. Concurrent with the swap terminations, we entered into new interest rate swap agreements, with identical terms as the previous swap agreements; however, the floating rate of interest was based upon a spread of an additional 50 basis points. In December 2002, the swap agreements entered into in July 2002 were terminated, resulting in a gain of approximately $26.9 million. The gains realized from the July 2002 and December 2002 swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes. At December 31, 2004, the unamortized balance of the deferred gains was $36.6 million. In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the consolidated statement of income at the time of extinguishment.

NOTE 5. ACQUISITIONS AND DISPOSITIONS

Jonah Gas Gathering Company

On September 30, 2001, we purchased Jonah from Alberta Energy Company for $359.8 million, with an additional payment of $7.3 million made on February 4, 2002, for final purchase adjustments related primarily to construction projects in progress at the time of closing. The acquisition served as our entry into the natural gas gathering industry. We funded the acquisition through a borrowing under a bank credit facility. We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets for gas gathering contracts. We also recognized goodwill on the purchase of approximately $2.8 million. We accounted for the acquisition under the purchase method of accounting. Accordingly, the results of operations of the acquisition have been included in our consolidated financial statements from September 30, 2001. Under a contractual agreement, DEFS manages and operates Jonah on our behalf.

The following table allocates the estimated fair value of Jonah assets acquired on September 30, 2001, and includes the additional purchase adjustment paid on February 4, 2002 (in thousands):

Property, plant and equipment	$	141,835
Intangible assets (primarily gas gathering contracts)		222,800
Goodwill		2,777
Other		147
Total assets		367,559
Total liabilities assumed		(489)
Net assets acquired	$	367,070

The value assigned to intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production. We are amortizing the value assigned to intangible assets on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the contracts (averaging approximately 35 years) (see Note 3. Goodwill and Other Intangible Assets).

Chaparral NGL System

On March 1, 2002, we purchased the Chaparral NGL system ("Chaparral") for $132.4 million from Diamond-Koch II, L.P. and Diamond-Koch III, L.P., including acquisition related costs of approximately $0.4 million. The Chaparral NGL system extends from West Texas and New Mexico to Mont Belvieu. The pipeline delivers NGLs to fractionators and to our existing storage facilities in Mont Belvieu. We funded the purchase through borrowings under a bank credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. Accordingly, the results of the acquisition have been included in our consolidated financial statements from March 1, 2002. Under a contractual agreement, DEFS manages and operates Chaparral on our behalf.

Val Verde Gas Gathering Company

On June 30, 2002, we purchased Val Verde for $444.2 million from Burlington Resources Gathering Inc., a subsidiary of Burlington Resources Inc., including acquisition related costs of approximately $1.2 million. The Val Verde system gathers CBM from the Fruitland Coal Formation of the San Juan Basin in New Mexico and Colorado. The system is one of the largest CBM gathering and treating facilities in the United States. The purchase was primarily funded through borrowings under bank credit facilities. We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets for gas gathering contracts. We accounted for the acquisition of these assets under the purchase method of accounting. Accordingly, the results of the acquisition have been included in our consolidated financial statements from June 30, 2002. Under a contractual agreement, DEFS manages and operates Val Verde on our behalf.

The following table allocates the estimated fair value of the Val Verde assets acquired on June 30, 2002 (in thousands):

Property, plant and equipment	$	205,146
Intangible assets (primarily gas gathering contracts)		239,649
Total assets		444,795
Total liabilities assumed		(645)
Net assets acquired	$	444,150

The value assigned to intangible assets relates to fixed-term contracts with customers. We are amortizing the value assigned to intangible assets on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the contracts. The period of amortization is expected to be approximately 30 years from the date of acquisition.

The following table presents our unaudited pro forma results as though the acquisition of Val Verde occurred at the beginning of 2002 (in thousands, except per Unit amounts). The unaudited pro forma results give effect to certain pro forma adjustments including depreciation and amortization expense adjustments of property, plant and equipment and intangible assets based upon the purchase price allocations, interest expense related to financing the acquisition, amortization expense of debt issue costs and the removal of income tax effects in historical results of operations. The pro forma results do not include operating efficiencies or revenue growth from historical results.

Year Ended

		December 31, 2002
Revenues	$	3,279,948
Operating income		181,717
Net income		130,335
Basic and diluted net income per Unit	$	1.70

The summarized pro forma information has been prepared for comparative purposes only. It is not intended to be indicative of the actual operating results that would have occurred had the acquisition been consummated at the beginning of 2002, or the results which may be attained in the future.

Rancho Pipeline

In connection with our acquisition of crude oil assets in 2000, we acquired an approximate 23.5% undivided joint interest in the Rancho Pipeline, which was a crude oil pipeline system from West Texas to Houston, Texas. In March 2003, the Rancho Pipeline ceased operations, and segments of the pipeline were sold to certain of the owners that previously held undivided interests in the pipeline. We acquired 241 miles of the pipeline in exchange for cash of $5.5 million and our interests in other portions of the Rancho Pipeline. We sold 183 miles of the segment we acquired to other entities for cash and assets valued at approximately $8.5 million. We recorded a net gain of $3.9 million on the transactions in the second quarter of 2003. During the third quarter of 2004, we sold our remaining interest in the original Rancho Pipeline system for a net gain of $0.4 million. These gains are included in the gains on sales of assets in our consolidated statements of income.

Genesis Pipeline

On November 1, 2003, we purchased crude supply and transportation assets along the upper Texas Gulf Coast for $21.0 million from Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. ("Genesis"). The transaction was funded with proceeds from our August 2003 equity offering (see Note 11. Partners' Capital and Distributions). We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets. The assets acquired included approximately 150 miles of small diameter trunk lines, 26,000 barrels per day of throughput and 12,000 barrels per day of lease marketing and supply business. We have integrated these assets into our South Texas pipeline system, which has allowed us to consolidate gathering and marketing assets in key operating areas in a cost effective manner and will provide future growth opportunities. Accordingly, the results of the acquisition are included in the consolidated financial statements from November 1, 2003.

The following table allocates the estimated fair value of the Genesis assets acquired on November 1, 2003 (in thousands):

Property, plant and equipment	$	12,811
Intangible assets		8,742
Other		144
Total assets		21,697
Total liabilities assumed		(687)
Net assets acquired	$	21,010

NOTE 6. EQUITY INVESTMENTS

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway Crude Pipeline Company ("Seaway"). The remaining 50% interest is owned by ConocoPhillips. Seaway owns a pipeline

that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of the Seaway partnership. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. During the years ended December 31, 2004 and 2003, we received distributions from Seaway of $36.9 million and $22.7 million, respectively.

In August 2000, TE Products entered into agreements with Panhandle Eastern Pipeline Company ("PEPL"), a former subsidiary of CMS Energy Corporation, and Marathon Ashland Petroleum LLC ("Marathon") to form Centennial Pipeline LLC ("Centennial"). Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Through February 9, 2003, each participant owned a one-third interest in Centennial. On February 10, 2003, TE Products and Marathon each acquired an additional 16.7% interest in Centennial from PEPL for $20.0 million each, increasing their ownership percentages in Centennial to 50% each. During the years ended December 31, 2004 and 2003, TE Products invested an additional $1.5 million and $24.0 million, respectively, in Centennial, which is included in the equity investment balance at December 31, 2004. The 2003 amount includes the $20.0 million paid for the acquisition of the additional ownership interest in Centennial. TE Products has not received any distributions from Centennial since its formation.

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") formed Mont Belvieu Storage Partners, L.P. ("MB Storage"). TE Products and Louis Dreyfus each own a 50% ownership interest in MB Storage. The purpose of MB Storage is to expand services to the upper Texas Gulf Coast energy marketplace by increasing pipeline throughput and the mix of products handled through the existing system and establishing new receipt and delivery connections. MB Storage is a service-oriented, fee-based venture with no commodity trading activity. TE Products operates the facilities for MB Storage. Effective January 1, 2003, TE Products contributed property and equipment with a net book value of $67.1 million to MB Storage. Additionally, as of the contribution date, Louis Dreyfus had invested $6.1 million for expansion projects for MB Storage that TE Products was required to reimburse if the original joint development and marketing agreement was terminated by either party. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in MB Storage.

TE Products receives the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement. Any amount of MB Storage's annual income before depreciation expense in excess of $7.15 million is allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2004 and 2003, TE Products' sharing ratio in the earnings of MB Storage was approximately 69.4% and 70.4%, respectively. For the years ended December 31, 2004 and 2003, excluding the contribution of property and equipment upon formation of the partnership, TE Products has contributed $21.4 million and $2.5 million, respectively, to MB Storage. The 2004 amount includes a contribution of $16.5 million for the acquisition of storage and pipeline assets in April 2004. The remaining contributions have been for capital expenditures in both periods. During the years ended December 31, 2004 and 2003, TE Products received distributions of $10.3 million and $5.3 million, respectively, from MB Storage.

We use the equity method of accounting to account for our investments in Seaway, Centennial and MB Storage. Summarized combined financial information for Seaway, Centennial and MB Storage for the years ended December 31, 2004 and 2003, is presented below (in thousands):

	Years Ended December 31, 2004	Years Ended December 31, 2003
Revenues	$ 149,843	$ 125,521
Net income	52,059	30,034

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of December 31, 2004, and December 31, 2003, is presented below (in thousands):

	December 31, 2004	December 31, 2003
Current assets	$ 59,314	$ 56,243
Noncurrent assets	633,222	609,215
Current liabilities	41,209	43,177
Long-term debt	140,000	140,000
Noncurrent liabilities	20,440	13,182
Partners' capital	490,887	469,099

NOTE 7. RELATED PARTY TRANSACTIONS

Duke Energy, DEFS and Affiliates

We have no employees and are managed by the Company, an indirect wholly owned subsidiary of DEFS. Duke Energy holds an interest of approximately 70% in DEFS, and ConocoPhillips holds the remaining interest of approximately 30%. According to the Partnership Agreements, the Company is entitled to reimbursement of all direct and indirect expenses related to our business activities (see Note 1. Partnership Organization).

For the years ended December 31, 2004, 2003, and 2002, we incurred direct expenses of $83.6 million, $78.0 million and $66.7 million, respectively, which were charged to us by DEFS. Substantially all of these costs were related to payroll and payroll related expenses. For the years ended December 31, 2004, 2003, and 2002, expenses for administrative services and overhead allocated to us by Duke Energy and its affiliates were $1.2 million, $1.1 million and $0.8 million, respectively.

TCO purchases condensate from DEFS and its affiliates. For the years ended December 31, 2004, 2003, and 2002, TCO's purchases from DEFS and its affiliates were $141.3 million, $110.7 million and $80.5 million, respectively.

Lubrication Services, L.P. ("LSI") sells lubrication oils and specialty chemicals to DEFS. For the years ended December 31, 2004, 2003, and 2002, revenues recognized by LSI included $16.1 million, $15.2 million and $14.6 million, respectively, for the sale of lubrication oils and specialty chemicals to DEFS.

Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado, LLC ("TEPPCO Colorado") and DEFS entered into a 20-year Fractionation Agreement, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Revenues recognized from the fractionation facilities totaled $7.5 million, $7.4 million and $7.4 million for the years ended December 31, 2004, 2003 and 2002, respectively. TEPPCO Colorado and DEFS also entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS. Expenses related to the Operation and Maintenance Agreement totaled $0.9 million for each of the years ended December 31, 2004, 2003 and 2002.

The Dean Pipeline and the Wilcox Pipeline were included with the crude oil assets purchased from DEFS effective November 1, 1998. The southern portion of the Dean Pipeline originates in South Texas and transports NGLs for DEFS into its pipeline in Point Comfort, Texas. Revenues recognized from DEFS for NGL transportation totaled $0.2 million, $1.0 million and $2.9 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Wilcox Pipeline, which is located along the Texas Gulf Coast, transports NGLs for DEFS from two of its processing plants and is currently supported by a throughput agreement with DEFS through November 2005. The fees paid to us by DEFS under the agreement were $1.4 million, $1.5 million and $1.2 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The Panola Pipeline and San Jacinto Pipeline were purchased on December 31, 2000, from DEFS for $91.7 million. These pipelines originate at DEFS' East Texas Plant Complex in Panola County, Texas, and transport NGLs for DEFS and other major integrated oil and gas companies. Revenues recognized from an affiliate of DEFS for NGL transportation totaled $11.3 million, $9.2 million and $12.0 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Effective May 2001, we entered into an agreement with an affiliate of DEFS to commit to it sole utilization of our Providence terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. The agreement was renegotiated in May 2004. During the years ended December 31, 2004, 2003 and 2002, revenues of $4.3 million, $3.2 million and $2.3 million, respectively, from an affiliate of DEFS were recognized pursuant to this agreement.

On September 30, 2001, we purchased Jonah (see Note 5. Acquisitions and Dispositions). The Jonah assets are managed and operated by employees of DEFS under a contractual agreement under which DEFS is reimbursed for its actual costs. During the years ended December 31, 2004, 2003 and 2002, we recognized $4.1 million, $3.7 million and $3.3 million, respectively, of expenses related to the operation and management of the Jonah assets by DEFS. Jonah provides gas gathering services to an affiliate of DEFS. The gathering fees paid to us by an affiliate of DEFS totaled $3.3 million, $2.0 million and $1.2 million for the years ended December 31, 2004, 2003 and 2002, respectively. In connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004, Jonah sells NGLs to, and purchases gas from, an affiliate of DEFS. For the year ended December 31, 2004, Jonah's sales to DEFS and its affiliates were $7.1 million, and purchases from DEFS and its affiliates were $5.1 million. In addition, processing fees we received from an affiliate of DEFS for gas processing services at the Pioneer plant totaled $0.6 million for the year ended December 31, 2004.

On March 1, 2002, we purchased the Chaparral NGL system (see Note 5. Acquisitions and Dispositions). The Chaparral assets are managed and operated by employees of DEFS under a contractual agreement under which DEFS is reimbursed for its actual costs. During the years ended December 31, 2004, 2003, and 2002, we recognized $2.3 million, $2.1 million and $1.7 million, respectively, of expenses related to the operation and management of the Chaparral assets by DEFS. An affiliate of DEFS transports NGLs on the Chaparral NGL system. The fees paid to us by an affiliate of DEFS for NGL transportation on the Chaparral NGL system totaled $3.8 million, $5.5 million and $4.5 million for the years ended December 31, 2004, 2003 and 2002, respectively.

On June 30, 2002, we purchased Val Verde (see Note 5. Acquisitions and Dispositions). The Val Verde assets are managed and operated by employees of DEFS under a contractual agreement under which DEFS is reimbursed for its actual costs. During the years ended December 31, 2004, 2003 and 2002, we recognized $3.8 million, $3.0 million and $1.2 million, respectively, of expenses related to the operation and management of the Val Verde assets by DEFS.

At December 31, 2004 and 2003, we had a receivable from DEFS of $10.5 million and $1.8 million, respectively, related to sales and transportation services provided to DEFS. Included in this receivable balance from DEFS at December 31, 2004, is a gas imbalance receivable of $0.9 million. At December 31, 2004 and 2003, we

had a payable to DEFS of $22.4 million and $15.0 million, respectively, related to direct payroll, payroll related costs, management fees, and other operational related charges, including those for Jonah, Chaparral and Val Verde as described above. Included in this payable balance at December 31, 2004 and 2003, is a gas imbalance payable to DEFS of $3.2 million and $1.5 million, respectively.

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO (see Note 11. Partners' Capital and Distributions).

We contract with Bison Insurance Company Limited ("Bison"), a wholly owned subsidiary of Duke Energy, for a majority of our insurance coverage, including property, liability, auto and directors and officers insurance coverage. For the years ended December 31, 2004, 2003 and 2002, we incurred insurance expense related to premiums paid to Bison of $6.5 million, $5.9 million and $3.8 million, respectively. At December 31, 2004 and 2003, we had insurance reimbursement receivables due from Bison of $5.2 million and $4.2 million, respectively.

At December 31, 2003, we had a loan of propane outstanding to DEFS with a total value of $1.4 million. We earned a nominal rental fee of $0.1 million on this transaction. This propane was returned to us in February 2004. We regularly loan inventory for a fee to third parties and affiliates as part of our inventory management practice.

Seaway

We own a 50% ownership interest in Seaway, and the remaining 50% interest is owned by ConocoPhillips (see Note 6. Equity Investments). We are the operator of Seaway. During the years ended December 31, 2004, 2003 and 2002, we billed Seaway $7.6 million, $7.4 million and $7.1 million, respectively, for direct payroll and payroll related expenses for operating Seaway. Additionally, for each of the years ended December 31, 2004, 2003 and 2002, we billed Seaway $2.1 million for indirect management fees for operating Seaway. At December 31, 2004 and 2003, we had a payable balance to Seaway of $0.5 million and $4.0 million, respectively, for advances Seaway paid to us as operator for operating costs, including payroll and related expenses and management fees.

Centennial

In August 2000, TE Products entered into agreements with PEPL and Marathon to form Centennial (see Note 6. Equity Investments). At December 31, 2004, TE Products had a 50% ownership interest in Centennial. TE Products has entered into a management agreement with Centennial to operate Centennial's terminal at Creal Springs, Illinois, and pipeline connection in Beaumont, Texas. For each of the years ended December 31, 2004, 2003 and 2002, we recognized management fees of $0.2 million from Centennial, and actual operating expenses billed to Centennial were $6.9 million, $4.4 million and $4.0 million, respectively.

TE Products also has a joint tariff with Centennial to deliver products at TE Products' locations using Centennial's pipeline as part of the delivery route to connecting carriers. TE Products, as the delivering pipeline, invoices the shippers for the entire delivery rate, records only the net rate attributable to it as transportation revenues and records a liability for the amounts due to Centennial for its share of the tariff. At December 31, 2004 and 2003, we had payable balances of $2.8 million and $2.3 million, respectively, to Centennial for its share of the joint tariff deliveries and other operational related charges. In addition, TE Products performs ongoing construction services for Centennial and bills Centennial for labor and other costs to perform the construction. At December 31, 2004 and 2003, TE Products had receivable balances of $1.1 million and $1.3 million, respectively, due from Centennial for reimbursement of construction services provided to Centennial.

In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the years ended December 31, 2004 and 2003, TE Products incurred $5.3 million and $3.8 million, respectively, of rental charges related to the lease of pipeline capacity on Centennial.

MB Storage

Effective January 1, 2003, TE Products entered into agreements with Louis Dreyfus to form MB Storage (see Note 6. Equity Investments). TE Products operates the facilities for MB Storage. TE Products and MB Storage have entered into a pipeline capacity lease agreement, and for each of the years ended December 31, 2004 and 2003, TE Products recognized $0.1 million in rental revenue related to this lease agreement. During the years ended December 31, 2004 and 2003, TE Products also billed MB Storage $3.2 million and $2.5 million, respectively, for direct payroll and payroll related expenses for operating MB Storage. At December 31, 2004, TE Products had a net receivable balance from MB Storage of $1.3 million for operating costs, including payroll and related expenses for operating MB Storage. At December 31, 2003, TE Products had a net payable balance to MB Storage of $0.2 million for advances MB Storage paid for operating costs.

NOTE 8. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at December 31, 2004 and 2003. The major components of inventories were as follows (in thousands):

	December 31, 2004	December 31, 2003
Crude oil	$ 3,690	$ 1,303
Refined products	5,665	6,632
LPGs	—	517
Lubrication oils and specialty chemicals	4,002	3,080
Materials and supplies	6,135	4,528
Other	29	—
Total	$ 19,521	$ 16,060

NOTE 9. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment for the years ended December 31, 2004 and 2003, were as follows (in thousands):

	December 31, 2004	December 31, 2003
Land and right of way	$ 135,984	$ 130,775
Line pipe and fittings	1,344,193	1,256,393
Storage tanks	140,690	135,938
Buildings and improvements	41,205	35,648
Machinery and equipment	333,363	292,949
Construction work in progress	115,937	112,817
Total property, plant and equipment	$ 2,111,372	$ 1,964,520
Less accumulated depreciation and amortization	407,670	345,357
Net property, plant and equipment	$ 1,703,702	$ 1,619,163

Depreciation expense on property, plant and equipment was $80.7 million, $64.5 million and $56.0 million for the years ended December 31, 2004, 2003 and 2002, respectively. During the fourth quarter of 2004, we wrote off approximately $2.1 million in assets taken out of service to depreciation expense.

We evaluate impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. During the third quarter of 2004, we completed an evaluation of our marine terminal facility in the Beaumont, Texas, area. The facility consists primarily of a barge dock, a ship dock, four storage tanks and various segments of connecting pipelines and is included in our Downstream Segment. The evaluation indicated that the docks and other assets at the facility needed extensive work to continue to be commercially operational. As a result, we performed an impairment test on the entire marine facility and recorded a $4.4 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the fair value of the facility.

NOTE 10. DEBT

Senior Notes

On January 27, 1998, TE Products completed the issuance of $180.0 million principal amount of 6.45% Senior Notes due 2008, and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively the "TE Products Senior Notes"). The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and are being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 are not subject to redemption prior to January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, may be redeemed at any time after January 15, 2008, at the option of TE Products, in whole or in part, at a premium.

The TE Products Senior Notes do not have sinking fund requirements. Interest on the TE Products Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The TE Products Senior Notes are unsecured obligations of TE Products and rank on a parity with all other unsecured and unsubordinated indebtedness of TE Products. The indenture governing the TE Products Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2004, TE Products was in compliance with the covenants of the TE Products Senior Notes.

On February 20, 2002, we completed the issuance of $500.0 million principal amount of 7.625% Senior Notes due 2012. The 7.625% Senior Notes were issued at a discount of $2.2 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 7.625% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2004, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. We used $182.0 million of the proceeds from the offering to reduce the outstanding principal on our $500.0 million revolving credit facility to $250.0 million. The balance of the net proceeds received was used for general partnership purposes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and

leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2004, we were in compliance with the covenants of these Senior Notes.

The following table summarizes the estimated fair values of the Senior Notes as of December 31, 2004 and 2003 (in millions):

	Face Value	Fair Value December 31, 2004	Fair Value December 31, 2003
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 187.1	$ 190.1
7.625% Senior Notes, due February 2012	500.0	569.6	566.3
6.125% Senior Notes, due February 2013	200.0	210.2	206.1
7.51% TE Products Senior Notes, due January 2028	210.0	225.6	222.4

We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the Senior Notes discussed above (see Note 4. Interest Rate Swaps).

Other Long Term Debt and Credit Facilities

On April 6, 2001, we entered into a $500.0 million revolving credit facility including the issuance of letters of credit of up to $20.0 million ("Three Year Facility"). The interest rate was based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Three Year Facility contained certain restrictive financial covenant ratios. During the first quarter of 2003, we repaid $182.0 million of the outstanding balance of the Three Year Facility with proceeds from the issuance of our 6.125% Senior Notes on January 30, 2003. On June 27, 2003, we repaid the outstanding balance under the Three Year Facility with borrowings under a new credit facility, and canceled the Three Year Facility.

On June 27, 2003, we entered into a $550.0 million revolving credit facility with a three year term, including the issuance of letters of credit of up to $20.0 million ("Revolving Credit Facility"). The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Revolving Credit Facility contains certain restrictive financial covenant ratios. We borrowed $263.0 million under the Revolving Credit Facility and repaid the outstanding balance of the Three Year Facility. On October 21, 2004, we amended our Revolving Credit Facility to (i) increase the facility size to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing. On December 31, 2004, $353.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 3.0%. At December 31, 2004, we were in compliance with the covenants of this credit agreement.

The following table summarizes the principal amounts outstanding under all of our credit facilities as of December 31, 2004 and 2003 (in thousands):

	December 31, 2004	December 31, 2003
Credit Facilities:		
Revolving Credit Facility, due October 2009	$ 353,000	$ 210,000
6.45% TE Products Senior Notes, due January 2008	179,906	179,876
7.625% Senior Notes, due February 2012	498,438	498,216
6.125% Senior Notes, due February 2013	198,845	198,702
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,440,189	1,296,794
Adjustment to carrying value associated with hedges of fair value	40,037	42,856
Total Credit Facilities	$ 1,480,226	$ 1,339,650

NOTE 11. PARTNERS' CAPITAL AND DISTRIBUTIONS

Equity Offerings

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO. We received approximately $0.7 million in proceeds from the offering in excess of the amount needed to repurchase and retire the Class B Units.

On August 7, 2003, we sold in an underwritten public offering 5.0 million Units at $34.68 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $166.0 million. On August 19, 2003, 162,900 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on August 7, 2003. Proceeds from the over-allotment sale, net of underwriting discount, totaled $5.4 million. Approximately $53.0 million of the proceeds were used to repay indebtedness under our revolving credit facility and $21.0 million was used to fund the acquisition of the Genesis assets (see Note 5. Acquisitions and Dispositions). The remaining amount was used primarily to fund revenue-generating and system upgrade capital expenditures and for general partnership purposes.

Quarterly Distributions of Available Cash

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Pursuant to the Partnership Agreement, the Company receives incremental incentive cash distributions when cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target – $0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target – $0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target – Cash distributions greater than $0.45 per Unit	50%	50%

The following table reflects the allocation of total distributions paid during the years ended December 31, 2004, 2003 and 2002 (in thousands, except per Unit amounts):

	Years Ended December 31, 2004	2003	2002
Limited Partner Units	$ 166,158	$ 145,427	$ 104,932
General Partner Ownership Interest	3,391	3,016	2,329
General Partner Incentive	63,508	51,709	35,389
Total Partners' Capital Cash Distributions	233,057	200,152	142,650
Class B Units	—	2,346	9,203
Total Cash Distributions Paid	$ 233,057	$ 202,498	$ 151,853
Total Cash Distributions Paid Per Unit	$ 2.64	$ 2.50	$ 2.35

On February 7, 2005, we paid a cash distribution of $0.6625 per Unit for the quarter ended December 31, 2004. The fourth quarter 2004 cash distribution totaled $58.7 million.

General Partner Interest

As of December 31, 2004 and 2003, we had deficit balances of $33.0 million and $7.2 million, respectively, in our General Partner's equity account. This negative balance does not represent an asset to us and does not represent an obligation of the General Partner to contribute cash or other property to us. The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Consolidated Statements of Partners' Capital for a detail of the General Partner's equity account). For the years ended December 31, 2004 and 2003, the General Partner was allocated $41.1 million (representing 28.85%) and $34.8 million (representing 27.65%), respectively, of our net income and received $66.9 million and $54.7 million, respectively, in cash distributions.

Capital Accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our 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 accounting principles generally accepted in the United States in our financial statements. Under our Partnership Agreement, the General Partner is required to make additional capital contributions to us upon the issuance of any additional Units if necessary to maintain a Capital Account balance equal to 1.999999% of the total Capital Accounts of all partners. At December 31, 2004 and 2003, the General Partner's Capital Account balance substantially exceeded this requirement.

Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period. This is generally consistent with the manner of allocating net income under our Partnership Agreement. Net income determined under our Partnership Agreement, however, incorporates principles established for U.S. federal income tax purposes and is not comparable to net income reflected under accounting principles generally accepted in the United States in our financial statements.

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Cash distributions in excess of net income allocations and capital contributions during the years ended December 31, 2004 and 2003, resulted in a deficit in the General Partner's equity account at December 31, 2004 and 2003. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

According to the Partnership Agreement, in the event of our dissolution, after satisfying our liabilities, our remaining assets would be divided among our limited partners and the General Partner generally in the same proportion as Available Cash but calculated on a cumulative basis over the life of the Partnership. If a deficit balance still remains in the General Partner's equity account after all allocations are made between the partners, the General Partner would not be required to make whole any such deficit.

NOTE 12. CONCENTRATIONS OF CREDIT RISK

Our primary market areas are located in the Northeast, Midwest and Southwest regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. We thoroughly analyze our customers' historical and future credit positions prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments and guarantees.

For each of the years ended December 31, 2004, 2003 and 2002, we had one customer from the Upstream Segment, Valero Energy Corp., which accounted for 16% of our total consolidated revenues. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2004, 2003 and 2002.

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature.

NOTE 13. UNIT-BASED COMPENSATION

1994 Long Term Incentive Plan

During 1994, the Company adopted the Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan ("1994 LTIP"). The 1994 LTIP provides certain key employees with an incentive award whereby a participant is granted an option to purchase Units. These same employees are also granted a stipulated number of Performance Units, the cash value of which may be used to pay for the exercise of the respective Unit options awarded. Under the provisions of the 1994 LTIP, no more than one million options and two million Performance Units may be granted.

When our calendar year earnings per unit (exclusive of certain special items) exceeds a stated threshold, each participant receives a credit to their respective Performance Unit account equal to the earnings per unit excess multiplied by the number of Performance Units awarded. The balance in the Performance Unit account may be used to offset the cost of exercising Unit options granted in connection with the Performance Units or may be withdrawn two years after the underlying options expire, usually 10 years from the date of grant. Any unused balance previously credited is forfeited upon termination. We accrue compensation expense for the Performance Units awarded annually based upon the terms of the plan discussed above.

Under the agreement for such Unit options, the options become exercisable in equal installments over periods of one, two, and three years from the date of the grant. At December 31, 2004, all options have been fully exercised. The Performance Unit account has a minimal liability balance which may be withdrawn by the participants after December 31, 2006.

A summary of Unit options granted under the terms of the 1994 LTIP is presented below:

	Options Outstanding	Options Exercisable	Exercise Range
Unit Options:			
Outstanding at December 31, 2001	189,688	143,822	$13.81 - $25.69
Became exercisable	—	45,866	$25.25
Exercised	(99,597)	(99,597)	$13.81 - $25.69
Outstanding at December 31, 2002	90,091	90,091	$13.81 - $25.69
Exercised	(90,091)	(90,091)	$13.81 - $25.69
Outstanding at December 31, 2003	—	—	

We have not granted options for any periods presented. During the year ended December 31, 2003, all remaining outstanding Unit options were exercised. For options previously outstanding, we followed the intrinsic value method for recognizing stock-based compensation expense. The exercise price of all options awarded under the 1994 LTIP equaled the market price of our Units on the date of grant. Accordingly, we recognized no compensation expense at the date of grant. Had compensation expense been determined consistent with SFAS No. 123, *Accounting for Stock-Based Compensation*, compensation expense related to option grants would have been immaterial for the year ended December 31, 2002, and no compensation expense would have been recognized for the years ended December 31, 2004 and 2003.

1999 and 2002 Phantom Unit Plans

Effective September 1, 1999, the Company adopted the Texas Eastern Products Pipeline Company, LLC 1999 Phantom Unit Retention Plan ("1999 PURP"). Effective June 1, 2002, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan ("2002 PURP"). The 1999 PURP and the 2002 PURP provide key employees with incentive awards whereby a participant is granted phantom units. These phantom units are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at stated redemption dates. The fair market value of each phantom unit is equal to the closing price of a Unit as reported on the New York Stock Exchange on the redemption date.

Under the agreement for the phantom units, each participant will vest 10% of the number of phantom units initially granted under his or her award at the end of each of the first four years and will vest the final 60% at the end of the fifth year. Each participant is required to redeem their phantom units as they vest. They are also entitled to quarterly cash distributions equal to the product of the number of phantom units outstanding for the participant and the amount of the cash distribution that we paid per Unit to unitholders. A total of 1,800 phantom units granted under the 1999 PURP remain outstanding at December 31, 2004. A total of 57,600 phantom units granted under the 2002 PURP remain outstanding at December 31, 2004. We accrue compensation expense annually based upon the terms of the 1999 PURP and 2002 PURP discussed above. At December 31, 2004 and 2003, we had an accrued liability balance of $1.6 million and $2.1 million, respectively, for compensation related to the 1999 PURP and 2002 PURP.

2000 Long Term Incentive Plan

Effective January 1, 2000, the General Partner established the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is

based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period. At December 31, 2004, phantom units outstanding were 23,600, 30,600 and 21,200 for awards granted for the years ended December 31, 2004, 2003 and 2002, respectively.

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. For purposes of the 2000 LTIP for plan years 2000 through 2002, EBITDA means our earnings before net interest expense, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that in its discretion the Compensation Committee of the General Partner may exclude gains or losses from extraordinary, unusual or non-recurring items. For the years ended December 31, 2004 and 2003, EBITDA means, in addition to the above, earnings before other income – net. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, *plus* products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by the Compensation Committee at the date of award grant.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2000 LTIP discussed above. At December 31, 2004 and 2003, we had an accrued liability balance of $2.4 million and $2.9 million, respectively, for compensation related to the 2000 LTIP.

NOTE 14. OPERATING LEASES

We use leased assets in several areas of our operations. Total rental expense for the years ended December 31, 2004, 2003 and 2002, was $22.1 million, $18.8 million and $14.2 million, respectively. The following table sets forth our minimum rental payments under our various operating leases for the years ending December 31 (in thousands):

2005	$ 18,178
2006	15,991
2007	12,698
2008	7,406
2009	5,465
Thereafter	19,568
	$ 79,306

NOTE 15. EMPLOYEE BENEFITS

Retirement Plans

We have adopted the TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP"), which is a non-contributory, trustee-administered pension plan. In addition, certain executive officers participate in the TEPPCO

Supplemental Benefit Plan ("TEPPCO SBP"), which is a non-contributory, nonqualified, defined benefit retirement plan. The TEPPCO SBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans. The benefit formula for all eligible employees is a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit based upon pay credits and current interest credits. The pay credits are based on a participant's salary, age and service. We use a December 31 measurement date for these plans.

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2004, 2003 and 2002, were as follows (in thousands):

	2004	2003	2002
Service cost benefit earned during the year	$ 3,653	$ 3,179	$ 2,925

Interest cost on projected benefit obligation	719	504	315
Expected return on plan assets	(878)	(604)	(390)
Amortization of prior service cost	7	7	7
Recognized net actuarial loss	57	24	12
Net pension benefits costs	$ 3,558	$ 3,110	$ 2,869

Other Postretirement Benefits

Effective January 1, 2001, we provide employees with certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees become eligible for these benefits if they meet certain age and service requirements at retirement, as defined in the plans. We provide a fixed dollar contribution, which does not increase from year to year, towards retired employee medical costs. The retiree pays all health care cost increases due to medical inflation. We use a December 31 measurement date for this plan.

The components of net postretirement benefits cost for the TEPPCO OPB for the years ended December 31, 2004, 2003 and 2002, were as follows (in thousands):

	2004	2003	2002
Service cost benefit earned during the year	$ 165	$ 137	$ 115
Interest cost on accumulated postretirement benefit obligation	153	137	119
Amortization of prior service cost	126	126	126
Recognized net actuarial loss	1	—	—
Net postretirement benefits costs	$ 445	$ 400	$ 360

We employ a building block approach in determining the long-term rate of return for plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with a widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established via a building block approach with proper consideration of diversification and rebalancing. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

The weighted average assumptions used to determine benefit obligations for the retirement plans and other postretirement benefit plans at December 31, 2004 and 2003, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	5.75%	6.25%	5.75%	6.25%
Increase in compensation levels	5.00%	5.00%	—	—

The weighted average assumptions used to determine net periodic benefit cost for the retirement plans and other postretirement benefit plans for the years ended December 31, 2004 and 2003, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	6.25%	6.75%	6.25%	6.75%
Increase in compensation levels	5.00%	5.00%	—	—
Expected long-term rate of return on plan assets	8.00%	8.00%	—	—

The following table sets forth our pension and other postretirement benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2004 and 2003 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
Change in benefit obligation				
Benefit obligation at beginning of year	$ 11,256	$ 7,578	$ 2,467	$ 2,001
Service cost	3,653	3,179	165	137
Interest cost	719	504	153	137
Actuarial (gain)/loss	572	236	205	209
Retiree contributions	—	—	60	54
Benefits paid	(260)	(241)	(86)	(71)
Benefit obligation at end of year	$ 15,940	$ 11,256	$ 2,964	$ 2,467
Change in plan assets				
Fair value of plan assets at beginning of year	$ 10,921	$ 6,820	$ —	$ —
Actual return on plan assets	808	650	—	—
Retiree contributions	—	—	60	54
Employer contributions	3,500	3,692	26	17
Benefits paid	(260)	(241)	(86)	(71)
Fair value of plan assets at end of year	$ 14,969	$ 10,921	$ —	$ —
Reconciliation of funded status				

Funded status	$ (971)	$ (335)	$ (2,964)	$ (2,467)
Unrecognized prior service cost	33	40	1,003	1,129
Unrecognized actuarial loss	2,006	1,421	472	267
Net amount recognized	$ 1,068	$ 1,126	$ (1,489)	$ (1,071)

Plan Assets

We employ a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, both growth and value equity style, and small, mid and large capitalizations. Investment risk and return parameters are reviewed and evaluated periodically to ensure compliance with stated investment objectives and guidelines. This comprehensive review incorporates investment portfolio performance, annual liability measurements and periodic asset/liability studies.

The following table sets forth the weighted average asset allocations for the retirement plans and other postretirement benefit plans as of December 31, 2004 and 2003, by asset category (in thousands):

	December 31,	
Asset Category	**2004**	**2003**
Equity securities	63%	47%
Debt securities	35%	30%
Other (money market and cash)	2%	23%
Total	100%	100%

We expect to contribute approximately $3.5 million to our retirement plans and other postretirement benefit plans in 2005.

Other Plans

DEFS also sponsors an employee savings plan, which covers substantially all employees. Plan contributions on behalf of the Company of $3.5 million, $3.2 million and $2.8 million were recognized during the years ended December 31, 2004, 2003 and 2002, respectively.

NOTE 16. COMMITMENTS AND CONTINGENCIES

In the fall of 1999 and on December 1, 2000, the General Partner and the Partnership were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership) and *Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership). In both cases, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaints, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On January 27, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs and the Richards plaintiffs dismissing all of these plaintiffs' claims. The settlement terms include a $2.0 million payment to the plaintiffs, which has been accrued for in our consolidated financial statements. The terms of the settlements did not have a material adverse effect on our financial position, results of operations or cash flows.

Although we did not settle with all plantiffs and we therefore remain named parties in the *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al*. action, a co-defendant has agreed to indemnify us for all remaining claims asserted against us. Consequently, we do not believe that the outcome of

these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs have not stipulated the amount of damages they are seeking in the suit; however, this case is covered by insurance. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On April 19, 2002, we, through our subsidiary TEPPCO Crude Oil, L.P., filed a declaratory judgment action in the U.S. District Court for the Western District of Oklahoma against D.R.D. Environmental Services, Inc. ("D.R.D.") seeking resolution of billing and other contractual disputes regarding potential overcharges for environmental remediation services provided by D.R.D. On May 28, 2002, D.R.D. filed a counterclaim for alleged breach of contract in the amount of $2,243,525, and for unspecified damages for alleged tortious interference with D.R.D.'s contractual relations with DEFS. On July 16, 2003, the parties entered into a Settlement Agreement and Mutual Release, dismissing all claims and counterclaims against each other. The terms of the Settlement Agreement and Mutual Release did not have a material adverse effect on our financial position, results of operations or cash flows.

In May 2003, the General Partner was named as a defendant in a lawsuit styled *John R. James, et al. v. J Graves Insulation Company, et al.* as filed in the first Judicial District Court, Caddo Parish, Louisiana. There are numerous plaintiffs identified in the action that are alleged to have suffered damages as the result of alleged exposure to asbestos-containing products and materials. According to the petition and as a result of a preliminary investigation, the General Partner believes that the only claim asserted against it results from one individual for the period from July 1971 through June 1972, who is alleged to have worked on a facility owned by the General Partner's predecessor. This period represents a small portion of the total alleged exposure period from January 1964 through December 2001 for this individual. The individual's claims involve numerous employers and alleged job sites. The General Partner has been unable to confirm involvement by the General Partner or its predecessors with the alleged location, and it is uncertain at this time whether this case is covered by insurance. Discovery is planned, and the General Partner intends to defend itself vigorously against this lawsuit. The plaintiffs have not stipulated the amount of damages that they are seeking in this suit. We are obligated to reimburse the General Partner for any costs it incurs related to this lawsuit. We cannot estimate the loss, if any, associated with this pending lawsuit. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On April 2, 2003, Centennial was served with a petition in a matter styled *Adams, et al. v. Centennial Pipeline Company LLC, et al*. This matter involves approximately 2,000 plaintiffs who allege that over 200 defendants, including Centennial, generated, transported, and/or disposed of hazardous and toxic waste at two sites in Bayou Sorrell, Louisiana, an underground injection well and a landfill. The plaintiffs allege personal injuries, allergies, birth defects, cancer and death. The underground injection well has been in operation since May 1976. Based upon current information, Centennial appears to be a *de minimis* contributor, having used the disposal site during the two month time period of December 2001 to January 2002. Marathon has been handling this matter for Centennial under its operating agreement with Centennial. TE Products has a 50% ownership interest in Centennial. On November 30, 2004, the court approved a class settlement. The time period for parties to appeal this settlement has not expired, however, and the settlement will not be final until it does so. If the approved class settlement becomes final, the terms of the settlement will not have a material adverse effect on our financial position, results of operations or cash flows.

On December 16, 2003, Centennial, the General Partner, the Partnership and other Partnership entities were named as defendants in a lawsuit in the 128th District Court of Orange County, Texas, styled *Elwood Karr et al. v. Centennial Pipeline, LLC et al*. In this case, the plaintiffs contend that our pipeline leaked toxic substances on their property, causing them property damage. On October 29, 2004, the parties entered into a Settlement Agreement, dismissing all claims. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

On February 4, 2005, we received a letter notifying us of a claim for approximately $1.45 million in damages allegedly due to a shipper being delivered off-specification gasoline during November 2004. We are contesting liability for this matter, and to the extent there may be liability, we would seek reimbursement from the third party refiner who supplied the gasoline into our pipeline system. We do not believe that the outcome of this matter will have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

On February 7, 2005, we received a letter from BP Amoco's counsel placing us on notice of a lawsuit filed by ConocoPhillips against BP Amoco Seaway Products Pipeline Company. Pursuant to provisions of the Amended and Restated Purchase Agreement dated May 10, 2000, between us and ARCO Pipe Line Company (BP Amoco), BP Amoco requested indemnity should BP Amoco have any liability to ConocoPhillips. The litigation arises out of an income tax liability alleged by ConocoPhillips due to a partnership merger. The plaintiff estimates the income tax liability to be $3,964,788. We have requested information from BP Amoco that will allow us to assess liability, if any, that we may have in this matter. We do not believe that the outcome of this lawsuit will have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

In addition to the litigation discussed above, we have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by insurance. We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of injunctions delaying or prohibiting certain activities and the need to perform investigatory and remedial activities. Although we believe our operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure you that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental laws and regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us. We believe that changes in environmental laws and regulations will not have a material adverse effect on our financial position, results of operations or cash flows in the near term.

On March 26, 2004, an initial decision in *ARCO Products Co., et al. v. SFPP*, Docket OR96-2-000, et al. was issued by the FERC, which made several significant determinations with respect to finding "changed circumstances" under the Energy Policy Act of 1992 ("EP Act"). The decision largely clarifies, but does not fully quantify, the standard required for a complainant to demonstrate that an oil pipeline's rates are no longer subject to the rate protection of the EP Act by demonstrating that a substantial change in circumstances has occurred since 1992 with respect to the basis of the rates being challenged. In the decision, the FERC found that a limited number of rate elements will significantly affect the economic basis for a pipeline company's rates. The elements identified in the decision are volume changes, allowed total return and total cost-of-service (including major cost elements of rate base such as tax rates and tax allowances, among others). The FERC did reject, however, the use of changes in tax rate and income tax allowances as standalone factors. It appears likely that the decision will be appealed. We have not yet determined the impact, if any, that the decision, if it is ultimately upheld, would have on our rates if they were reviewed under the criteria of this decision.

On July 20, 2004, the Court of Appeals for the District of Columbia Circuit issued an opinion in *BP West Coast Producers LLC v. FERC*. In reviewing a series of orders involving SFPP, L.P. the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for 42.7% of the net operating (pre-tax) income expected from operations and was denied an income tax allowance equal to 57.3% of its limited partnership interests that were held by non-corporate partners. The court remanded the case back to the FERC for further review. As a result of the court's remand, the FERC on December 2, 2004, issued a Request for Comments seeking comments on whether the court's ruling applies only to the specific facts of the SFPP, L.P. proceeding or also extends to other capital structures involving partnerships and other forms of ownership. The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

In 1994, the Louisiana Department of Environmental Quality ("LDEQ") issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. At December 31, 2004, we have an accrued liability of $0.2 million for remediation costs at our Arcadia facility. Effective in March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On March 17, 2003, we experienced a release of 511 barrels of jet fuel from a storage tank at our Blue Island terminal located in Cook County, Illinois. As a result of the release, we have entered into an Agreed Order with the State of Illinois which required us to conduct an environmental investigation. At this time, we have complied with the terms of the Agreed Order, and the results of the environmental investigation indicated there were no soil or groundwater impacts from the release. We are in the process of negotiating a final settlement with the State of Illinois, and we do not expect that compliance with the settlement will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 22, 2004, we experienced a release of approximately 12 barrels of jet fuel from a sump at our Lebanon, Ohio, terminal. The released jet fuel was contained within a storm water retention pond located on the terminal property. Six migratory waterfowl were affected by the jet fuel and were subsequently euthanized by or at the request of the United States Fish and Wildlife Service ("USFWS"). On October 1, 2004, the USFWS served us with a Notice of Violation, alleging that we violated 16 USC 703 of the Migratory Bird Treaty Act for the "take[ing] of migratory birds by illegal methods." On February 7, 2005, we entered into a Memorandum of Understanding with the USFWS, settling all aspects of this matter. The terms of this settlement did not have a material effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, is seeking a civil penalty against us for alleged violations of the Clean Water Act ("CWA") arising out of this release. The maximum statutory penalty calculated for this alleged violation of the CWA is $2.8 million. We are in discussions with the DOJ regarding this matter and have responded to its request for additional information. We do not expect a civil penalty, if any, to have a material adverse effect on our financial position, results of operations or cash flows.

At December 31, 2004, we have an accrued liability of $5.0 million, related to various TCTM and TE Products sites requiring environmental remediation activities. At December 31, 2003, we had an accrued liability of $5.9 million related to various TCTM sites requiring environmental remediation activities. Under the terms of a 1998 agreement through which we acquired various crude oil assets from DETTCO, we received a five year contractual indemnity obligation for certain environmental liabilities attributable to the operations of the assets prior to our acquisition. Concurrent with the expiration of this indemnity in 2003, we entered into a Settlement Agreement and Release with DETTCO releasing DETTCO from future obligations pertaining to certain environmental liabilities, requiring us to share in certain costs for the remediation of a crude oil site in Oklahoma, and the assumption of responsibility by DETTCO for environmental liabilities associated with three sites located in Texas and Oklahoma. We do not expect that the completion of remediation programs associated with TCTM and TE Products activities will have a future material adverse effect on our financial position, results of operations or cash flows.

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2004, $150.0 million was outstanding under those credit facilities. The proceeds were used to fund construction and conversion

costs of its pipeline system. TE Products and Marathon have each guaranteed one-half of Centennial's debt, up to a maximum amount of $75.0 million each.

Rates of interstate petroleum products and crude oil pipeline companies, like us, are currently regulated by the FERC primarily through an index methodology, which allows a pipeline to change its rates based on the change from year to year in the Producer Price Index for finished goods ("PPI Index"). Effective as of February 24, 2003, FERC Order on Remand modified the PPI Index from PPI – 1% to PPI. On April 22, 2003, several shippers filed a petition in the United States Court of Appeals for the District of Columbia Circuit (the "Court"), *Flying J. Inc,. Lion Oil Company, Sinclair Oil Corporation and Tesoro Refining and Marketing Company vs. Federal Energy Regulatory Commission*; Docket No. 03-1107, seeking a review of whether the FERC's adoption of the PPI Index was reasonable and supported by the evidence. On April 9, 2004, the Court handed down a decision denying the shippers' petition for review, stating the shippers failed to establish that any of the FERC's methodological choices (or combination of choices) were both erroneous and harmful.

As an alternative to using the PPI Index, interstate petroleum products and crude oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements between shippers and petroleum products and crude oil pipeline companies that the rate is acceptable.

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2004, TCTM and TE Products had approximately 2.9 million barrels and 20.8 million barrels, respectively, of products in their custody that was owned by customers. We are obligated for the transportation, storage and delivery of such products on behalf of our customers. We maintain insurance adequate to cover product losses through circumstances beyond our control.

We carry insurance coverage consistent with companies engaged in similar operations with similar type properties. Our insurance coverage includes (1) commercial general public liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage, and (4) property insurance covering the replacement value of all real and personal property damage, including damages arising from earthquake, flood damage and business interruption/extra expense. For select assets, we also carry pollution liability insurance that provides coverage for historical and gradual pollution events. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

We also maintain excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are comparable to those carried by other energy companies of similar size. The cost of our general insurance coverages continued to fluctuate over the past year reflecting the changing conditions of the insurance markets. These insurance policies, except for the pollution liability policies, are with Bison Insurance Company Limited, an insurance company that is wholly owned by Duke Energy (see Note 7. Related Party Transactions).

NOTE 17. SEGMENT INFORMATION

We have three reporting segments:

- transportation and storage of refined products, LPGs and petrochemicals, which operates as the Downstream Segment;

- gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, which operates as the Upstream Segment; and

- gathering of natural gas, fractionation of NGLs and transportation of NGLs, which operates as the Midstream Segment.

The amounts indicated below as “Partnership and Other” relate primarily to intersegment eliminations and assets that we hold that have not been allocated to any of our reporting segments.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand in the Northeast for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports, refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 6. Equity Investments).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway. Seaway consists of large diameter pipelines that transport crude oil from Seaway’s marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the fractionation of NGLs in Colorado, transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of CBM and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde. DEFS manages and operates the Val Verde, Jonah and Chaparral assets for us under contractual agreements. The results of operations of the acquisitions are included in our consolidated financial statements in periods subsequent to their respective acquisition dates (see Note 5. Acquisitions and Dispositions).

The tables below include financial information by reporting segment for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Year Ended December 31, 2004					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 5,426,832	$ 7,295	$ 5,434,127	$ —	$ 5,434,127
Operating revenues	279,400	49,163	198,709	527,272	(3,207)	524,065
Purchases of petroleum products	—	5,370,234	5,944	5,376,178	(3,207)	5,372,971
Operating expenses, including power	165,528	60,893	59,826	286,247	—	286,247
Depreciation and amortization expense	43,135	13,130	56,629	112,894	—	112,894
Gains on sales of assets	(526)	(527)	—	(1,053)	—	(1,053)
Operating income	71,263	32,265	83,605	187,133	—	187,133
Equity earnings (losses)	(3,402)	29,383	—	25,981	—	25,981
Other income, net	787	406	127	1,320	—	1,320
Earnings before interest	$ 68,648	$ 62,054	$ 83,732	$ 214,434	$ —	$ 214,434

	Year Ended December 31, 2003					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 3,766,651	$ —	$ 3,766,651	$ —	$ 3,766,651
Operating revenues	266,427	39,564	185,105	491,096	(1,915)	489,181
Purchases of petroleum products	—	3,713,122	—	3,713,122	(1,915)	3,711,207

Operating expenses, including power	151,103	57,314	47,020	255,437	—	255,437
Depreciation and amortization expense	31,620	11,311	57,797	100,728	—	100,728
Gain on sale of assets	—	(3,948)	—	(3,948)	—	(3,948)
Operating income	83,704	28,416	80,288	192,408	—	192,408
Equity earnings (losses)	(4,086)	20,949	—	16,863	—	16,863
Other income, net	226	306	289	821	(73)	748
Earnings before interest	$ 79,844	$ 49,671	$ 80,577	$ 210,092	$ (73)	$ 210,019

	Year Ended December 31, 2002					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum Products	$ —	$ 2,823,800	$ —	$ 2,823,800	$ —	$ 2,823,800
Operating revenues	243,538	37,900	138,922	420,360	(1,997)	418,363
Purchases of petroleum products	—	2,774,325	—	2,774,325	(1,997)	2,772,328
Operating expenses, including power	130,324	49,781	33,451	213,556	—	213,556
Depreciation and amortization expense	30,116	11,186	44,730	86,032	—	86,032
Operating income	83,098	26,408	60,741	170,247	—	170,247
Equity earnings (losses)	(6,815)	18,795	—	11,980	—	11,980
Other income, net	832	1,532	269	2,633	(806)	1,827
Earnings before interest	$ 77,115	$ 46,735	$ 61,010	$ 184,860	$ (806)	$ 184,054

The following table provides the total assets, capital expenditures and significant non-cash investing activites for each segment as of and for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
December 31, 2004:						
Total assets	$ 968,993	$ 1,070,477	$ 1,184,184	$ 3,223,654	$ (25,949)	$ 3,197,705
Capital expenditures	80,930	37,448	45,075	163,453	694	164,147
December 31, 2003:						
Total assets	$ 916,917	$ 834,502	$ 1,194,844	$ 2,946,263	$ (5,271)	$ 2,940,992
Capital expenditures	59,061	13,427	67,882	140,370	147	140,517
Non-cash investing activities	61,042	—	—	61,042	—	61,042
December 31, 2002:						
Total assets	$ 881,101	$ 724,860	$ 1,174,139	$ 2,780,100	$ (11,678)	$ 2,768,422
Capital expenditures	60,900	10,212	62,260	133,372	—	133,372

The following table reconciles the segments total earnings before interest to consolidated net income for the three years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Earnings before interest	$ 214,434	$ 210,019	$ 184,054
Interest expense – net	(72,053)	(84,250)	(66,192)
Net income	$ 142,381	$ 125,769	$ 117,862

NOTE 18. COMPREHENSIVE INCOME

SFAS No. 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on certain investments to be reported in a financial statement. As of and for the years ended December 31, 2004, 2003 and 2002, the components of comprehensive income were due to the interest rate swap related to our variable rate revolving credit facility, which was designated as a cash flow hedge. The interest rate swap matured in April 2004. While the interest rate swap was in effect, changes in the fair value of the cash flow hedge, to the extent the hedge was effective, were recognized in other comprehensive income until the hedge interest costs were recognized in net income. As of December 31, 2004, all other comprehensive income has been recognized in net income.

The table below reconciles reported net income to total comprehensive income for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Net income	$ 142,381	$ 125,769	$ 117,862

Net income on cash flow hedges	—	16,164	269
Total comprehensive income	$ 142,381	$ 141,933	$ 118,131

The accumulated balance of other comprehensive loss related to our cash flow hedge is as follows (in thousands):

Balance at December 31, 2001	$ (20,324)
Transferred to earnings	12,883
Change in fair value of cash flow hedge	(12,614)
Balance at December 31, 2002	$ (20,055)
Reclassification due to discontinued portion of cash flow hedge	989
Transferred to earnings	14,417
Change in fair value of cash flow hedge	1,747
Balance at December 31, 2003	$ (2,902)
Transferred to earnings	2,939
Change in fair value of cash flow hedge	(37)
Balance at December 31, 2004	$ —

NOTE 19. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our significant operating subsidiaries, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P., have issued unconditional guarantees of our debt securities. The guarantees are full, unconditional, and joint and several. TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. are collectively referred to as the “Guarantor Subsidiaries.”

The following supplemental condensed consolidating financial information reflects our separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of our other non-guarantor subsidiaries, the combined consolidating adjustments and eliminations and our consolidated accounts for the dates

and periods indicated. For purposes of the following consolidating information, our investments in our subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting.

	December 31, 2004				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 44,125	$ 87,068	$ 576,365	$ (62,928)	$ 644,630
Property, plant and equipment – net	—	1,211,312	492,390	—	1,703,702
Equity investments	1,021,476	430,688	203,796	(1,282,308)	373,652
Intercompany notes receivable	1,084,034	—	—	(1,084,034)	—
Intangible assets	—	372,621	34,737	—	407,358
Other assets	5,980	22,183	40,200	—	68,363
Total assets	$ 2,155,615	$ 2,123,872	$ 1,347,488	$ (2,429,270)	$ 3,197,705
Liabilities and partners' capital					
Current liabilities	$ 45,255	$ 143,589	$ 556,474	$ (62,930)	$ 682,388
Long-term debt	1,086,909	393,317	—	—	1,480,226
Intercompany notes payable	—	676,993	407,040	(1,084,033)	—
Other long term liabilities	2,003	9,980	1,660	—	13,643
Total partners' capital	1,021,448	899,993	382,314	(1,282,307)	1,021,448
Total liabilities and partners' capital	$ 2,155,615	$ 2,123,872	$ 1,347,488	$ (2,429,270)	$ 3,197,705

	December 31, 2003				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P Consolidated
			(in thousands)		
Assets					
Current assets	$ 38,281	$ 92,817	$ 360,564	$ (38,844)	$ 452,818
Property, plant and equipment – net	—	1,146,455	472,708	—	1,619,163
Equity investments	1,112,252	404,886	209,438	(1,361,290)	365,286
Intercompany notes receivable	943,447	—	—	(943,447)	—
Intangible assets	—	401,404	37,161	—	438,565
Other assets	6,157	21,444	37,559	—	65,160
Total assets	$ 2,100,137	$ 2,067,006	$ 1,117,430	$ (2,343,581)	$ 2,940,992
Liabilities and partners' capital					
Current liabilities	$ 41,895	$ 105,285	$ 367,260	$ (38,849)	$ 475,591
Long-term debt	947,486	392,164	—	—	1,339,650
Intercompany notes payable	—	557,842	385,604	(943,446)	—
Other long term liabilities	1,435	14,995	—	—	16,430
Total partners' capital	1,109,321	996,720	364,566	(1,361,286)	1,109,321
Total liabilities and partners' capital	$ 2,100,137	$ 2,067,006	$ 1,117,430	$ (2,343,581)	$ 2,940,992

	Year Ended December 31, 2004				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 430,162	$ 5,531,237	$ (3,207)	$ 5,958,192
Costs and expenses	—	301,568	5,473,751	(3,207)	5,772,112
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Operating income	—	129,120	58,013	—	187,133
Interest expense – net	—	(48,902)	(23,151)	—	(72,053)
Equity earnings	142,381	61,287	29,383	(207,070)	25,981
Other income – net	—	876	444	—	1,320
Net income	$ 142,381	$ 142,381	$ 64,689	$ (207,070)	$ 142,381

	Year Ended December 31, 2003				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 399,504	$ 3,858,243	$ (1,915)	$ 4,255,832
Costs and expenses	—	262,971	3,806,316	(1,915)	4,067,372
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Operating income	—	136,533	55,875	—	192,408
Interest expense – net	—	(52,903)	(31,420)	73	(84,250)
Equity earnings	125,769	41,678	20,949	(171,533)	16,863
Other income – net	—	461	360	(73)	748
Net income	$ 125,769	$ 125,769	$ 45,764	$ (171,533)	$ 125,769

	Year Ended December 31, 2002				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 336,045	$ 2,908,115	$ (1,997)	$ 3,242,163
Costs and expenses	—	216,552	2,857,361	(1,997)	3,071,916
Operating income	—	119,493	50,754	—	170,247
Interest expense – net	—	(40,651)	(26,347)	806	(66,192)
Equity earnings	117,862	38,053	18,795	(162,730)	11,980
Other income – net	—	967	1,666	(806)	1,827
Net income	$ 117,862	$ 117,862	$ 44,868	$ (162,730)	$ 117,862

	Year Ended December 31, 2004				
	TEPPCO Partners, L .P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from operating activities					
Net income	$ 142,381	$ 142,381	$ 64,689	$ (207,070)	$ 142,381
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	90,048	22,846	—	112,894
Earnings in equity investments, net of distributions	90,676	(3,963)	7,517	(72,998)	21,232
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Changes in assets and liabilities and other	(158,726)	29,679	(31,887)	151,690	(9,244)
Net cash provided by operating activities	74,331	257,619	62,638	(128,378)	266,210
Cash flows from investing activities	98	(34,060)	(39,907)	(115,331)	(189,200)
Cash flows from financing activities	(90,057)	(229,206)	(25,575)	254,781	(90,057)
Net decrease in cash and cash equivalents	(15,628)	(5,647)	(2,844)	11,072	(13,047)
Cash and cash equivalents at beginning of period	19,744	19,243	5,670	(15,188)	29,469
Cash and cash equivalents at end of period	$ 4,116	$ 13,596	$ 2,826	$ (4,116)	$ 16,422

	Year Ended December 31, 2003				
	TEPPCO Partners, L .P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from operating activities					
Net income	$ 125,769	$ 125,769	$ 45,764	$ (171,533)	$ 125,769

Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	80,114	20,614	—	100,728
Earnings in equity investments, net of distributions	76,729	3,559	1,791	(70,939)	11,140
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Changes in assets and liabilities and other	48,432	5,576	(1,995)	(46,348)	5,665
Net cash provided by operating activities	250,930	215,018	62,226	(288,820)	239,354
Cash flows from investing activities	(175,568)	(178,682)	(34,519)	203,531	(185,238)
Cash flows from financing activities	(55,618)	(25,340)	(44,758)	70,101	(55,615)
Net increase (decrease) in cash and cash equivalents	19,744	10,996	(17,051)	(15,188)	(1,499)
Cash and cash equivalents at beginning of period	—	8,247	22,721	—	30,968
Cash and cash equivalents at end of period	$ 19,744	$ 19,243	$ 5,670	$ (15,188)	$ 29,469

	Year Ended December 31, 2002				
	TEPPCO Partners, L .P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
	(in thousands)				
Cash flows from operating activities					
Net income	$ 117,862	$ 117,862	$ 44,868	$ (162,730)	$ 117,862
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization	—	66,175	19,857	—	86,032
Earnings in equity investments, net of distributions	33,994	18,879	11,586	(46,058)	18,401
Changes in assets and liabilities and other	(269,102)	48,638	40,254	192,832	12,622
Net cash provided by (used in) operating activities	(117,246)	251,554	116,565	(15,956)	234,917
Cash flows from investing activities	(378,039)	(1,150,967)	(253,879)	1,058,170	(724,715)
Cash flows from financing activities	495,285	904,006	138,210	(1,042,214)	495,287
Net increase in cash and cash equivalents	—	4,593	896	—	5,489
Cash and cash equivalents at beginning of period	—	3,654	21,825	—	25,479
Cash and cash equivalents at end of period	$ —	$ 8,247	$ 22,721	$ —	$ 30,968

NOTE 20. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per Unit amounts)			
2004				
Operating revenues	$ 1,318,061	$ 1,354,564	$ 1,490,010	$ 1,795,557
Operating income	53,901	42,401	37,081	53,750
Net income	40,433	37,759	25,855	38,334
Basic and diluted income per Limited Partner and Class B Unit	$ 0.46	$ 0.43	$ 0.29	$ 0.43
2003				
Operating revenues	$ 1,099,239	$ 1,040,800	$ 1,066,889	$ 1,048,904
Operating income	51,342	47,986	45,265	47,815
Net income	33,925	33,944	30,491	27,409
Basic and diluted income per Limited Partner and Class B Unit (1)(2)	$ 0.43	$ 0.43	$ 0.36	$ 0.31

(1) The sum of the four quarters does not equal the total year due to rounding.

(2) Per Unit calculation includes 3,938,750 Units issued in April 2003, 3,916,547 Units repurchased and retired in April 2003, 5,162,900 Units issued in August 2003, and 87,307 Units issued through the exercise of Unit options in 2003.

NOTE 21. SUBSEQUENT EVENT

On February 24, 2005, Texas Eastern Products Pipeline Company, LLC, our General Partner, was acquired by EPCO, Inc. (“EPCO”), a privately held company controlled by Dan L. Duncan. The acquisition was valued at $1.1 billion. Additionally, in a separate transaction, EPCO and its affiliates have agreed to purchase 2.5 million of our Units, valued at approximately $100.0 million, from Duke Energy. EPCO and its affiliates own the general partner of Enterprise Products Partners L.P. (“Enterprise”) and approximately 145 million Enterprise common units. Enterprise is one of the largest publicly traded master limited partnerships. The general partners of both TEPPCO Partners, L.P. (“TEPPCO”) and Enterprise will continue to operate independently and will maintain separate boards of directors, management teams and offices.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
SECOND AMENDED AND RESTATED
NONEMPLOYEE DIRECTORS UNIT ACCUMULATION PLAN

Texas Eastern Products Pipeline Company, LLC, a Delaware limited liability company (the "Company"), hereby establishes, effective January 1, 2004, a Unit Accumulation Plan (the "Plan"). This Second Amended and Restated Unit Accumulation Plan ("Plan"), providing for the automatic deferral of a certain portion of each Director's annual stipend as described below, is hereby established by Texas Eastern Products Pipeline Company, LLC, a Delaware limited liability company ("Company"):

1. Eligibility

Any member of the Board of Directors of the Company who is not also an employee of Duke Energy Corporation, the Company, or any other company affiliated with Duke Energy Corporation including but not limited to Duke Energy Field Services, LLC ("Director"), shall participate under the Plan ("Participant").

1. Fees to be Deferred and Length of Deferral

Each Director shall have a portion of his/her annual directors fees paid in the form of TEPPCO Partners phantom LP Units ("Phantom Units"), which shall automatically be deferred until the director terminates his/her services as a Director, or if later, a specified age. Each Director shall be credited with 100 Phantom Units on the last day of each calendar quarterly period (i.e. March 31, June 30, September 30 and December 31), provided that Participant was a member of the Board of Directors during such quarterly period.

2. Time and Method of Election to Defer

a. Each Participant may elect on an election form that has been approved by the Committee to have the amounts deferred under this Plan become payable upon the later of termination as a Director or attainment of a specified age; provided, however, that if the Participant does not file an election, such amounts shall become payable upon termination as a Director.

b. An election to defer distribution until a specified age shall be irrevocable and shall apply to all amounts deferred under this Plan unless revoked by a new Deferral Election Form filed prior to December 31 of the year preceding the calendar year in which the Participant ceases to be a Director.

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3. Phantom Unit Account

The Company shall establish a Phantom Unit account ("TEPPCO LP Account") in the name of each Participant, which shall be deemed invested in, or liquidated from, whole and fractional TEPPCO Partners LP Units, based upon the closing price of a TEPPCO Partners LP Unit as reported on the NYSE Composite Reporting System as of the trading day immediately following the last day of each calendar quarterly period, or the last day of the year that immediately precedes payment of the balance of the TEPPCO LP Account in a lump sum or in an annual installment, whichever day is applicable. The Participant's TEPPCO LP Account shall be increased to reflect the TEPPCO Partners LP Units added on the last day of each calendar quarterly period as set forth in Section 2 of this Plan. The Participant's TEPPCO LP Account shall be adjusted for (i) Distribution Equivalents as determined pursuant to Section 9 of this Plan and (ii) investment gain or loss based upon the performance of the TEPPCO Partners LP Units. The Participant's TEPPCO LP Account shall be decreased to reflect any payment of the balance thereof. TEPPCO LP Accounts shall be maintained by the Company in accordance with such accounting rules and procedures as the Company, in its sole discretion, shall determine.

4. Time of Payment

The Company shall pay the balance of a Participant's TEPPCO LP Account, in a lump sum, or in five (5) annual installments, with the lump sum payment or the first installment payment, as the case maybe, being made by January 15 of the year next following the later of the year in which the Participant's service as a Director terminates or the Participant attains the elected age on the Deferral Election form. Subsequent installment payments (if any) shall be made by January 15 of subsequent years. All such payments shall be in cash.

5. Form of Payment

A Participant shall elect to have payment of the balance of the TEPPCO LP Account made in one of the following forms:

a. In a lump sum, the amount of which shall be the balance of the Participant's TEPPCO LP Account, as adjusted for Phantom Unit investment through the last day of the preceding year, provided Participant may elect to take such lump sum amount, without interest, in four (4) equal quarterly installments during the calendar year in which such lump sum amount is payable with the first such quarterly payment made by January 15th of such year, or

b. In five (5) annual installments, the amount of each installment shall be the balance of the Participant's TEPPCO LP Account, as adjusted for Phantom Unit investment through the last day of the preceding year and

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for any installment previously paid, divided by the number of installments not yet paid. Participant's TEPPCO LP Account shall continue to be credited with Distribution Equivalents until such time as no balance remains in the account.

Notwithstanding the foregoing:

a. If at the close of the year during which the Participant's service as a Director terminates or the year in which the Participant attains the elected age on the Deferral Election form, whichever is later, the aggregate balance of the Participant's TEPPCO LP Account does not exceed $10,000.00, the aggregate balance of the Participant's TEPPCO LP Account shall be paid to the Participant in a lump sum by January 15 of the next following year; or

b. In the event of the Participant's death, the aggregate balance of the Participant's TEPPCO LP Account shall be paid to the Participant's beneficiary in a lump sum by January 15 of the year next following the year in which the Participant died.

7. Death Beneficiary

A Participant may designate a beneficiary or beneficiaries to receive the aggregate balance of the Participant's TEPPCO LP Account that is unpaid at the time of Participant's death. Such designation, including the revocation of any prior designation by a superseding designation, shall be made by completing the approved form and filing with the Secretary of the Company. A beneficiary designation by a Participant who is married at the time of his/her death which fails to name the Participant's surviving spouse as the sole beneficiary shall not be effective unless such surviving spouse has consented to the designation in writing, witnessed by the Secretary of the Company, another representative of the Committee or notary public, acknowledging the effect of the designation. Spousal consent shall not be required if, at the time of filing such designation, the Participant established to the satisfaction of the Secretary of the Company that the consent of the Participant's spouse could not be obtained because there is no spouse, the spouse could not be located or there exist such other mitigating circumstances as may be prescribed by the Secretary of the Company. Any spouse's consent (or establishment that the consent could not be obtained) shall be effective only with respect to that spouse. Any Participant may change his/her beneficiary designation at any time by filing with the Secretary of the Company a new beneficiary designation (with such spousal consent as may be required). Such designation shall not become effective until so filed and unless so filed prior to the time of Participant's death. In the event that a beneficiary designation is not in effect at the time of Participant's death or in the event that no designated beneficiary has survived the Participant's death, the Participant's estate shall be the Participant's sole beneficiary.

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8. Payments to Minors and Incompetents

Should the Participant become incompetent or should the Participant's beneficiary be a minor or incompetent, the Company is authorized to make payment to a parent or guardian of such minor or incompetent in full discharge of its obligations to such minor or incompetent under the Plan.

9. Distribution Equivalents

As soon as possible after each quarterly distribution date, TEPPCO shall credit to each Participant's TEPPCO LP Account a monetary amount ("Distribution Equivalents") equal to the product of:

1. the total number of Phantom Units in Participant's TEPPCO LP Account, multiplied by

2. the distribution paid with respect to a TEPPCO Partners, L.P. Unit for such quarter.

On the date that a quarterly credit of Phantom Units is made to a Participant's TEPPCO LP Account, any monetary balance in such account will be converted to additional Phantom Units in accordance with the provisions of Section 4 of this Plan.

10. Plan Administration

The Compensation Committee of the Board of Directors of the Company (the "Committee") is the administrator of the Plan, provided that any member of the Compensation Committee who is eligible under the Plan shall not participate in any matters or decisions constituting the administration of the Plan. As Plan administrator, the Committee shall have full and exclusive authority to control and manage the operation and administration of the Plan. The Committee may adopt such rules, and approve such forms, as may be necessary or desirable for the administration of the Plan and may delegate any of its duties and authority to others.

The Committee has the discretion:

1. To interpret and construe the terms and provisions of the Plan (including any rules adopted for the Plan);

2, To correct any defect, supply any omission, or reconcile any inconsistency in the Plan;

3. To decide any claim arising under the Plan; and

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4. To make factual determinations in connection with any of the foregoing.

A decision by the Committee with respect to any matter pertaining to the Plan shall be conclusive and binding on all interested parties.

11. Unfunded Plan

The Plan is unfunded. To the extent that a Participant or beneficiary acquires a right to receive payments from the Company under the Plan, such right shall not be greater than the right of an unsecured general creditor of the Company and such right shall be an unsecured claim against the general assets of the Company. Title to and beneficial ownership of any assets, whether cash or investments, which the Company may set aside in a grantor trust or otherwise earmark to pay its obligations hereunder will at all times remain the property of the

Company, and neither the Participant nor the Participant's estate or other beneficiary shall have any property interest whatsoever in any specific assets of the Company.

12. Nonassignability

The right of the Participant to receive payment from the Company under the Plan shall not be assigned, transferred, pledged, or encumbered except as provided by Section 7. Any attempted assignment, transfer, pledge, or encumbrance in violation of this Section 12 shall be null and void.

13. Amendment or Termination

The Plan may be amended from time to time or terminated by the Board of Directors of the Company, except that no amendment or termination shall, without the consent of the Participant, impair the rights of the Participant to receive payment of the aggregate balance of the Participant's TEPPCO LP Account.

14. Governing Law

The Plan, and all determinations made and actions taken pursuant thereto, to extent not governed by the provisions of the Internal Revenue Code or the securities laws of the United States, shall be governed by and construed in accordance with the laws of the state of Texas.

This Plan document has been executed on behalf of the Company this 11th day of February, 2004.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

By: /s/ BARRY R. PEARL
Its: Chief Executive Officer and President

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
AMENDED AND RESTATED
NONEMPLOYEE DIRECTORS FEE DEFERRAL PLAN

Deferral Election Form

To the Corporate Secretary:

Time of Payment

Pursuant to the Plan, I hereby elect to have amounts deferred under this Plan paid on the January 15th of the year next following the year specified below (Check one). I understand that regardless of my election, amounts deferred under this Plan can be paid no earlier than the January 15 of the year next following the calendar year in which my services as a Director terminate. I understand that I may change this election only by filing a new election form with you no later than the close of the calendar year preceding the calendar year with respect to which the superseding deferral election is to be effective.

o The year my services as a Director terminate

o The year I attain age ______, if later than the date my services as a Director terminate.

Payment Form Election

To the extent permitted by the Plan, I hereby elect that payment of the balance of the TEPPCO LP Account established pursuant to this Plan, which payment shall commence by January 15 of the year next following my termination of service as a Director, or if later, my attainment of the age specified above shall be in the form specified below. (Check one) I understand that this election is irrevocable.

o In one lump sum

o In five annual installments

I acknowledge that I have received a copy of the Plan and have read is provisions and that I agree to be bound thereby.

____
Print Name

____
Signature

Social Security Number

Date

Received by Corporate Secretary

Initial Date

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
AMENDED AND RESTATED
NONEMPLOYEE DIRECTORS FEE DEFERRAL PLAN

Beneficiary Designation Form

To the Corporate Secretary:

I hereby designate the following individual(s) as my Beneficiary(ies) under the Plan, provided he or she survives my death:

Name Name

Address Address

Social Security Number Social Security Number

If more than one designated Beneficiary survives my death, each surviving designated Beneficiary shall be paid an equal share unless I have expressly specified otherwise herein. *I understand that if I am married at the date of my death, my surviving spouse shall receive my entire TEPPCO LP Account, unless my spouse has consented (as provided below) to not being the sole beneficiary under the Plan.*

I understand that any aggregate balance of my TEPPCO LP Account remaining unpaid at my death shall be paid to my Beneficiary (ies) in a lump sum. I understand that in the event no designated Beneficiary survives my death, my estate shall be my Beneficiary.

I acknowledge that I have received a copy of the Plan and have read its provisions, and I agree to be bound thereby. This beneficiary designation revokes and supersedes any previous beneficiary designation made by me.

Signature Date

Printed Name SSN

SPOUSAL CONSENT *(must be completed if your spouse is not your sole beneficiary)* I understand that the Plan states that if we are married as of the date of my spouse's death, I will automatically receive my spouse's remaining deferral benefits, unless I waive this right. I consent to waive this right in accordance with the beneficiary designation set forth above. I understand that if I sign below, my consent is irrevocable unless my spouse revokes this beneficiary designation. I further understand that and acknowledge that if I sign below, no survivor benefit will be payable to me, except as may be provided above.

Signature Date

Printed Name SSN

ACKNOWLEDGMENT: On this day of [MONTH AND YEAR]. appeared before me and acknowledge that he/she is the spouse of and that he/she freely and voluntarily signed the foregoing consent for the use and purpose set forth therein.

My commission expires: Signature of notary public or plan representative:

Received by Corporate Secretary:

Initial Date

Exhibit 10.42

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

AMENDED AND RESTATED
NONEMPLOYEE DIRECTORS DEFERRED COMPENSATION PLAN

The Amended and Restated Nonemployee Directors Deferred Compensation Plan (the "Plan") is hereby established, effective April 1, 2002, by Texas Eastern Products Pipeline Company, LLC, a Delaware limited liability company (the "Company"), which plan provides for optional deferral of directors' fees, as described below:

1. Eligibility

Any member of the Board of Directors of the Company who is not also an employee of Duke Energy Corporation, the Company, or any other company affiliated with Duke Energy Corporation ("Director"), is eligible to participate under the Plan ("Participant").

2. Compensation to be Deferred

A Director may elect to defer any whole percentage of all directors' fees which may become payable to him or her with respect to services as a Director during any calendar year (the "year"). Directors' fees shall include retainer fees, committee fees, and attendance fees, but shall not include any expense reimbursement.

3. Time and Method of Election to Defer

a. In the first year in which a Participant becomes eligible to participate in the Plan (including the first year in which the Plan is in effect), the newly eligible Participant may make an election to defer directors' fees for services to be performed subsequent to such deferral election by completing the deferral election form that has been approved by the Committee ("Deferral Election Form"), and filing it with the Secretary of the Company within thirty (30) days after the date the Participant becomes eligible (or the date the Plan is first in effect).

b. A Participant may elect to defer directors' fees for any subsequent year by completing the Deferral Election Form and filing it with the Secretary of the Company before December 31 of the year preceding the year for which directors' fees shall be deferred.

c. A deferral election for a year shall be irrevocable and shall remain in effect and be deemed a like election for deferral of directors' fees for all subsequent years unless revoked by a new Deferral Election Form filed prior to December 31 of the year preceding the first year for which the new deferral election is to be effective. To the extent a deferral election is

not in effect for a year, directors' fees for such year shall be paid by the Company in accordance with its usual procedures.

4. Phantom Investment

Each time a Participant files a Deferral Election Form, the Company shall establish an account ("Deferred Compensation Account") in the name of the Participant. The Participant's Deferred Compensation Account shall be increased to reflect the directors' fees deferred by the Participant pursuant to the Deferral Election Form. The Participant's Deferred Compensation Account shall be adjusted for investment gain or loss based upon the phantom investment elected in the Deferral Election Form. The Participant's Deferred Compensation Account shall be decreased to reflect any payment of the balance thereof. Deferred Compensation Accounts shall be maintained by the Company in accordance with such accounting rules and procedures as the Company, in its sole discretion, shall determine. In the Deferral Election Form, the Participant shall irrevocably elect from among the following options, the phantom investment in the Deferred Compensation Account of the directors' fees deferred thereby:

100% Fixed Income Phantom Investment

100% LP Unit Phantom Investment

50% Fixed Income/50% LP Unit Phantom Investment

Fixed Income Phantom Investment - quarterly interest on the opening balance for the calendar quarter, at an annual rate of 7% or such other annual rate as a majority of the members of the Compensation Committee of the Board of Directors who are not eligible to participate under the Plan may, from time to time, establish.

LP Unit Phantom Investment - deemed invested in, or liquidated from, whole and fractional TEPPCO Partners LP Units, based upon the closing price of a TEPPCO Partners LP Unit as reported on the NYSE Composite Reporting System as of the trading day immediately preceding the day on which the directors' fees if not deferred would have been payable, the day on which quarterly cash distributions are paid to holders of TEPPCO Partners LP Units, or the last day of the year that immediately precedes payment of the balance of the Deferred Compensation Account in a lump sum or in an annual installment, whichever day is applicable.

Combined Fixed Income and LP Unit Phantom Investment. should the phantom investment in a Deferred Compensation Account be 50% Fixed Income/50% LP Unit, any payment of the balance of the Deferred Compensation Account shall be considered taken, to the extent possible, in equal amounts from each phantom investment.

5. Time of Payment

The Company shall pay the balance of a Participant's Deferred Compensation Account, in a lump sum, or in five annual installments as determined below, with the lump sum payment or, the first installment payment, as the case may be, being made by January 15 of the year next succeeding the year in which the Participant's service as a Director terminates. Subsequent installment payments shall be made by January 15 of subsequent years.

6. Form of Payment

In the Deferral Election Form that results in the establishment of the Deferred Compensation Account, a Participant shall elect to have payment of the balance of the Deferred Compensation Account made in one of the following forms:

a. In a lump sum, the amount of which shall be the balance of the Participant's Deferred Compensation Account, as adjusted for phantom investment through the last day of the preceding year; or

b. In five annual installments, the amount of each installment shall be the balance of the Participant's Deferred Compensation Account, as adjusted for phantom investment through the last day of the preceding year and for any installment previously paid, divided by the number of installments not yet paid.

Notwithstanding the foregoing:

a. If at the close of the year during which the Participant's service as a Director terminates, the aggregate balance of the Participant's Deferred Compensation Accounts does not exceed $10,000.00, the aggregate balance of the Participant's Deferred Compensation Accounts shall be paid to the Participant in a lump sum by January 15 of the next succeeding year; or

b. In the event of the Participant's death, the aggregate balance of the Participant's Deferred Compensation Accounts shall be paid to the Participant's beneficiary in a lump sum by January 15 of the year next succeeding the year in which the Participant died.

7. Death Beneficiary

A Participant may designate a beneficiary or beneficiaries to receive the aggregate balance of the Participant's Deferred Compensation Account that is unpaid at the time of Participant's death. Such designation, including the revocation of any prior designation by a superseding designation, shall be made by completing the approved form and filing with the Secretary of the Company. A beneficiary

designation by a Participant who is married at the time of his/her death which fails to name the Participant's surviving spouse as the sole beneficiary shall not be effective unless such surviving spouse has consented to the designation in writing, witnessed by the Secretary of the Company, another representative of the Committee or notary public, acknowledging the effect of the designation. Spousal consent shall not be required if, at the time of filing such designation, the Participant established to the satisfaction of the Secretary of the Company that the consent of the Participant's spouse could not be obtained because there is no spouse, the spouse could not be located or there exist such other mitigating circumstances as may be prescribed by the Secretary of the Company. Any spouse's consent (or establishment that the consent could not be obtained) shall be effective only with respect to that spouse. Any Participant may change his/her beneficiary designation at any time by filing with the Secretary of the Company a new beneficiary designation (with such spousal consent as may be required). Such designation shall not become effective until so filed and unless so filed prior to the time of Participant's death. In the event that a beneficiary designation is not in effect at the time of Participant's death or in the event that no designated beneficiary has survived the Participant's death, the Participant's estate shall be the Participant's sole beneficiary.

8. Payments to Minors and Incompetents

Should the Participant become incompetent or should the Participant's beneficiary be a minor or incompetent, the Company is authorized to make payment to a parent or guardian of such minor or incompetent in full discharge of its obligations to such minor or incompetent under the Plan.

9. Distribution Equivalents

As soon as possible after each quarterly distribution date, TEPPCO shall credit to each Participant's Deferred Compensation Account, a monetary amount ("Distribution Equivalents") equal to the product of:

(a) the total number of LP Unit phantom investments in Participant's Deferred Compensation Account, multiplied by

(b) the distribution paid with respect to a TEPPCO Partners, L.P. Unit for such quarter.

On the date that a credit to Participant's Deferred Compensation Account is made for LP Unit Phantom Investments any monetary balance in such account attributable to Distribution Equivalents will be converted to LP Unit Phantom Investments in accordance with the provisions of Section 4 subtitled LP Unit Phantom Investment.

10. Plan Administration

The Compensation Committee of the Board of Directors of the Company (the "Committee") is the administrator of the Plan, provided, that any member of the Committee who is eligible to participate under the Plan shall not participate in any decision on any matter regarding the administration of the Plan. As Plan administrator, the Committee shall have full and exclusive authority to control and manage the operation and administration of the Plan. The Committee may adopt such rules, and approve such forms, as may be necessary or desirable for the administration of the Plan and may delegate any of its duties and authority to others. The Committee has the discretion:

a. To interpret and construe the terms and provisions of the Plan (including any rules adopted for the Plan);

b. To correct any defect, supply any omission, or reconcile any inconsistency in the Plan;

c. To decide any claim arising under the Plan; and

d. To make factual determinations in connection with any of the foregoing.

A decision by the Committee with respect to any matter pertaining to the Plan shall be conclusive and binding on all interested parties.

11. Unfunded Plan

The Plan is unfunded. To the extent that a Participant or beneficiary acquires a right to receive payments from the Company under the Plan, such right shall not be greater than the right of an unsecured general creditor of the Company and such right shall be an unsecured claim against the general assets of the Company.

Title to and beneficial ownership of any assets, whether cash or investments, which the Company may set aside in a grantor trust or otherwise earmark to pay its obligations hereunder will at all times remain the property of the Company, and neither the Participant nor the Participant's estate or other beneficiary shall have any property interest whatsoever in any specific assets of the Company.

12. Nonassignability

The right of the Participant to receive payment from the Company under the Plan shall not be assigned, transferred, pledged, or encumbered except as provided by Section 7. Any attempted assignment, transfer, pledge, or encumbrance in violation of this Section 12 shall be null and void.

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13. Amendment or Termination

The Plan may be amended from time to time or terminated by the Board of Directors of the Company, except that no amendment or termination shall, without the consent of the Participant, impair the rights of the Participant to receive payment of the aggregate balance of the Participant's Deferred Compensation Accounts.

14. Governing Law

The Plan, and all determinations made and actions taken pursuant thereto, to extent not governed by the provisions of the Internal Revenue Code or the securities laws of the United States, shall be governed by and construed in accordance with the laws of the state of Texas.

This Plan document has been executed on behalf of the Company this 1st day of November, 2002.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

By: /s/ BARRY R. PEARL

Its: Chief Executive Officer and President

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges

	2000	2001	2002	2003	2004
			(in thousands)		
Earnings					
Income From Continuing Operations *	65,951	92,533	105,882	104,958	115,347
Fixed Charges	55,621	72,217	77,726	98,584	84,922
Distributed Income of Equity Investment	—	40,800	30,938	27,733	47,213
Capitalized Interest	(4,559)	(4,000)	(4,345)	(5,290)	(4,227)
Total Earnings	117,013	201,550	210,201	225,985	243,255
Fixed Charges					
Interest Expense	48,982	66,057	70,537	89,540	76,280
Capitalized Interest	4,559	4,000	4,345	5,290	4,227
Rental Interest Factor	2,080	2,160	2,844	3,754	4,415
Total Fixed Charges	55,621	72,217	77,726	98,584	84,922
Ratio: Earnings / Fixed Charges	2.10	2.79	2.70	2.29	2.86

* Excludes minority interest, extraordinary loss, gain on sale of assets and undistributed equity earnings.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the registration statement (No. 333-110207) on Form S-3, the registration statement (No. 33-81976) on Form S-3, and the registration statement (No. 333-82892) on Form S-8 of TEPPCO Partners, L.P. of our reports which appear in the December 31, 2004 annual report on Form 10-K of TEPPCO Partners, L.P:

- Dated February 24, 2005, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. as of December 31, 2004 and 2003, and the related consolidated statements of income, partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2004, and
- Dated February 24, 2005, with respect to management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 and the effectiveness of internal control over financial reporting as of December 31, 2004.

KPMG LLP

Houston, Texas
March 1, 2005

Exhibit 24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned directors and/or officers of TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC (the “Company”), a Delaware limited liability company, acting in its capacity as general partner of TEPPCO Partners, L.P., and TE Products Pipeline Company, Limited Partnership, each a Delaware limited partnership (collectively, “Partnership”), does hereby appoint CHARLES H. LEONARD, BARRY R. PEARL, and JAMES C. RUTH, and each of them, his true and lawful attorney and agent to do any and all acts and things, and execute any and all instruments which, with the advice and consent of Counsel, said attorney and agent may deem necessary or advisable to enable the Company and Partnership to comply with the Securities Act of 1934, as amended, and any rules, regulations, and requirements thereof, to sign his name as a director and/or officer of the Company to the Form 10-K Report for TEPPCO Partners, L.P. and for TE Products Pipeline Company, Limited Partnership, each for the year ended December 31, 2004, and to any instrument or document filed as a part of, or in accordance with, each said Form 10-K or amendment thereto; and the undersigned do hereby ratify and confirm all that said attorney and agent shall do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have subscribed these presents this 1st day of March, 2005.

/s/ MARK A. BORER Mark A. Borer Director	/s/ MICHAEL J. BRADLEY Michael J. Bradley Director
/s/ MILTON CARROLL Milton Carroll Director	/s/ DERRILL CODY Derrill Cody Director
/s/ JOHN P. DESBARRES John P. DesBarres Director	/s/ WILLIAM H. EASTER III William H. Easter III Director
/s/ PAUL F. FERGUSON, JR. Paul F. Ferguson, Jr. Director	/s/ JIM W. MOGG Jim W. Mogg Chairman
/s/ BARRY R. PEARL Barry R. Pearl Director	/s/ CHARLES H. LEONARD Charles H. Leonard Senior Vice President and Chief Financial Officer

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Barry R. Pearl, certify that:

1. I have reviewed this annual report on Form 10-K of TEPPCO Partners, L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and

   d) Disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 1, 2005

/s/ BARRY R. PEARL

Barry R. Pearl
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Charles H. Leonard, certify that:

1. I have reviewed this annual report on Form 10-K of TEPPCO Partners, L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and

   d) Disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 1, 2005

/s/ CHARLES H. LEONARD
Charles H. Leonard
Senior Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, being the Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, the sole general partner of TEPPCO Partners, L.P. (the “Company”), hereby certifies that, to his knowledge, the Company’s Annual Report on Form 10-K for the annual period ended December 31, 2004, filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to such Form 10-K. A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

March 1, 2005

Date

/s/ BARRY R. PEARL

Barry R. Pearl
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, being the Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, the sole general partner of TEPPCO Partners, L.P. (the “Company”), hereby certifies that, to his knowledge, the Company’s Annual Report on Form 10-K for the annual period ended December 31, 2004, filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to such Form 10-K. A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

March 1, 2005
Date

/s/ CHARLES H. LEONARD
Charles H. Leonard
Senior Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner