SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 1)
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year ended December 31, 2001

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 [x] No [ ]

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

At March 7, 2002, the aggregate market value of the registrant's Limited Partner Units held by non-affiliates was $1,240,803,750, which was computed using the average of the high and low sales prices of the Limited Partner Units on March 7, 2002.

Limited Partner Units outstanding as of March 7, 2002: 40,450,000.

Documents Incorporated by Reference: **None**

TABLE OF CONTENTS

PURPOSE OF THIS AMENDMENT

The Registrant is amending its Annual Report on Form 10-K for the year ended December 31, 2001, filed on March 14, 2002, to conform the Annual Report on Form 10-K to current segment presentation based upon segment changes that occurred effective January 1, 2002. Only those Items of Form 10-K that are being amended in this Report are included in this amendment. Notes 2, 4 and 15 to the Registrant's financial statements included herein have been revised to reflect the segment changes.

TEPPCO Partners, L.P. (“TEPPCO Partners”) reports and operates in three reporting 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”). TEPPCO Partners’ reportable segments offer different products and services and are managed separately because each requires different business strategies.

Effective January 1, 2002, TEPPCO Partners realigned its three reporting segments in order to separate and better measure the performance of its natural gas and NGL operations from its crude oil operations. The fractionation of NGLs, which was previously reflected as part of the Downstream Segment, was shifted to the Midstream Segment. The operation of NGL pipelines, which was previously reflected as part of the Upstream Segment, was also shifted to the Midstream Segment. The year-to-year comparisons have been adjusted to conform to the current presentation.

TABLE OF CONTENTS

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

General

TEPPCO Partners, L.P. (the “Partnership”), a Delaware limited partnership, is a master limited partnership and was formed in March 1990. The Partnership operates 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 the general partner of the Partnership. The General Partner is a wholly-owned subsidiary of Duke Energy Field Services (“DEFS”), a joint venture between Duke Energy Corporation (“Duke Energy”) and Phillips Petroleum Company (“Phillips”). Duke Energy holds an approximate 70% interest in DEFS and Phillips holds the remaining 30%. The Company, as general partner, performs all management and operating functions required for the Partnership and the Operating Partnerships, except for the management and operations of certain of the TEPPCO Midstream assets, which is performed by DEFS under an agreement with the Partnership. The General Partner is reimbursed by the Partnership for all reasonable direct and indirect expenses incurred in managing the Partnership.

On July 26, 2001, the Company restructured its general partner ownership of the Operating Partnerships to cause them to be indirectly wholly-owned by the Partnership. TEPPCO GP, Inc. (“TEPPCO GP”), a subsidiary of the Partnership, succeeded the Company as general partner of the Operating Partnerships. All remaining partner interests in the Operating Partnerships not already owned by the Partnership were transferred to the Partnership. In exchange for this contribution, the Company’s interest as general partner of the Partnership 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 the Partnership and the Operating Partnerships. As a result, the Partnership holds 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 guarantees of Partnership debt are issued by the Operating Partnerships.

The Partnership operates and reports 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”). The Partnership’s reportable segments offer different products and services and are managed separately because each requires different business strategies. The Upstream Segment of the Partnership’s business was initially acquired in November 1998. Portions of the Midstream Segment of the Partnership’s business were acquired in March 1998, November 1998, December 2000 and on September 30, 2001. Certain of the assets of the Midstream Segment are managed and operated by DEFS under an agreement with the Partnership.

Effective January 1, 2002, the Partnership realigned its three reporting segments in order to separate and better measure the performance of its natural gas and NGL operations from its crude oil operations. The fractionation of NGLs, which was previously reflected as part of the Downstream Segment, was shifted to the Midstream Segment. The operation of NGL pipelines, which was previously reflected as part of the Upstream Segment, was also shifted to the Midstream Segment. The year-to-year comparisons have been adjusted to conform to the current presentation.

The Partnership’s interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission (“FERC”). Refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas are referred to in this Report, collectively, as “petroleum products” or “products.”

At December 31, 2001, the Partnership had outstanding 40,450,000 Limited Partner Units and 3,916,547 Class B Limited Partner Units (“Class B Units”). All of the Class B Units were issued to Duke Energy in connection with an acquisition of assets initially acquired in the Upstream Segment in 1998. The Class B Units share in income and distributions on the same basis as the Limited Partner Units, but they are not listed on the New York Stock Exchange. The Class B Units may be converted into Limited Partner Units upon approval by the unitholders. The Company has the option to seek approval for the conversion of the Class B Units into Limited Partner Units; however, if the conversion is denied, Duke Energy, as holder of the Class B Units, will have the right to sell them to the Partnership at 95.5% of the then current market price of the Limited Partner Units. As a result of this option, the Class B Units were not included in partners' capital at December 31, 2001. Collectively, the Limited Partner Units and Class B Units are referred to as "Units."

The Partnership's strategy is to expand and improve service in its current markets, maintain the integrity of its pipeline systems and pursue a growth strategy that is balanced between internal projects and targeted acquisitions. The Partnership intends to leverage the advantages inherent in its pipeline systems to maintain its status as the incremental provider of choice in its market area. The Partnership also intends to grow by acquiring assets, from both third parties and affiliates, which complement existing businesses or to establish new core businesses. The Company routinely evaluates opportunities to acquire assets and businesses that will complement existing operations with a view to increasing earnings and cash available for distribution to unitholders. Additional acquisitions may be funded with cash flow from operations, borrowings under existing credit facilities, the issuance of debt in the capital markets and the sale of additional units.

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

Operations

The Partnership conducts business in its Downstream Segment through TE Products. TE Products owns and operates properties located in 13 states. These operations consist of interstate transportation, storage and terminaling of petroleum products; short-haul shuttle transportation of LPGs at the Mont Belvieu, Texas complex; intrastate transportation of petrochemicals and other ancillary services.

As an interstate common carrier, the 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 such 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 the pipeline system from its interstate tariffs, it also receives revenues from the shuttling of LPGs between refinery and petrochemical facilities on the upper Texas Gulf Coast and ancillary transportation, storage and marketing services at key points along the pipeline system. Substantially all the petroleum products transported and stored in the pipeline system are owned by TE Products' 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 to the Northeast.

The Partnership's Downstream Segment depends in large part on the level of demand for refined petroleum products and LPGs in the geographic locations served by it and the ability and willingness of customers having access to the pipeline system to supply such demand. The Partnership cannot predict the impact of future fuel conservation measures, alternate fuel requirements, governmental regulation, 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 served by the Partnership.

The following table lists the material properties and investments of and ownership percentages in the Downstream Segment assets as of December 31, 2001:

	Partnership Ownership
Refined products and LPGs pipeline	100%
Mont Belvieu LPGs storage and pipeline shuttle	100%
Mont Belvieu to Port Arthur, Texas, petrochemical pipelines	100%
Centennial Pipeline (1)	33%

(1) Accounted for as an equity investment.

Centennial Pipeline Joint Venture

In August 2000, TE Products entered into agreements with CMS Energy Corporation and Marathon Ashland Petroleum LLC to form a pipeline joint venture, Centennial Pipeline, LLC ("Centennial"). Centennial owns and operates an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to Illinois. Each participant owns a one-third interest in Centennial. 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 has constructed a new two million barrel refined petroleum products storage terminal. TE Products' interest is not subject to any encumbrances from mortgages or other secured debt. Centennial has unsecured debt, one third of which, up to $50 million in principal, is guaranteed by each owner, including TE Products. As of December 31, 2001, TE Products has contributed approximately $70 million for its one-third interest in Centennial. The Partnership expects to contribute an additional $4.9 million to Centennial in 2002. Centennial commenced operations in the first quarter of 2002.

Refined Products and LPGs Pipeline System

TE Products is one of the largest pipeline common carriers of refined petroleum products and LPGs in the United States. TE Products owns and operates an approximate 4,500-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, as well as substantial storage capacity at Mont Belvieu, Texas, the largest LPGs storage complex in the United States, and at other locations. TE Products also owns two marine receiving terminals, one near Beaumont, Texas, and the other at Providence, Rhode Island. The Providence terminal is not physically connected to the Products Pipeline System. The Products Pipeline System also includes three 12-inch diameter petrochemical pipelines between Mont Belvieu and Port Arthur, Texas, each approximately 70 miles in length.

All properties comprising the Products Pipeline System are wholly-owned by subsidiaries of the Partnership and none are subject to any encumbrances from mortgages or other secured debt.

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.

The Products Pipeline System includes 30 storage facilities with an aggregate storage capacity of 13 million barrels of refined petroleum products and 38 million barrels of LPGs, including storage capacity leased to outside parties. The Products Pipeline System makes deliveries to customers at 53 locations including 18 owned truck racks, rail car facilities and marine facilities. 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, Texas, 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, Indiana. The Products Pipeline System also has smaller diameter lines that extend laterally from El Dorado to Helena, Arkansas, from Tyler, Texas, 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 Tyler 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. Also, the Products Pipeline System 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 in Houston. In addition, there are numerous smaller diameter lines associated with the gathering and distribution system.

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, whereas the line starting at Greensburg and ending at Marcus Hook varies in diameter from 6 inches to 8 inches.

TE Products also owns two 12-inch diameter common carrier and one 12-inch diameter proprietary petrochemical pipelines between Mont Belvieu and Port Arthur, Texas, which were completed in the fourth quarter of 2000. Each of these pipelines is approximately 70 miles in length. The pipelines transport ethylene, propylene and natural gasoline. The Partnership entered into a 20-year agreement with a major petrochemical producer for guaranteed throughput commitments. During the year ended December 31, 2001, and the two month period ended December 31, 2000, the Partnership recognized $10.7 million and $1.8 million, respectively, of revenue under the throughput and deficiency contract. The Partnership began transporting product through these pipelines in September 2001.

The Partnership believes that the Products Pipeline System is in compliance with applicable federal, state and local laws and regulations, and accepted industry standards and practices. The Partnership performs regular maintenance on all the facilities of the Products Pipeline System and has an ongoing process of inspecting segments of the Products Pipeline System and making repairs and replacements when necessary or appropriate. In addition, the Partnership conducts periodic air patrols of the Products Pipeline System to monitor pipeline integrity and third-party right of way encroachments.

Table of Contents

Major Business Sector Markets

The Partnership's major operations in the Downstream Segment consist of the transportation, storage and terminaling of refined petroleum products and LPGs along its mainline system, and the storage and short-haul transportation of LPGs associated with its Mont Belvieu LPG operations. Product deliveries, in millions of barrels (MMBbls) on a regional basis, over the last three years were as follows:

	Product Deliveries (MMBbls) Years Ended December 31,		
	2001	2000	1999
Refined Products Mainline Transportation:			
Central (1)	62.0	63.4	67.7
Midwest (2)	37.4	36.7	37.9
Ohio and Kentucky	23.5	28.0	27.0
Subtotal	122.9	128.1	132.6
LPGs Mainline Transportation:			
Central, Midwest and Kentucky (1)(2)	23.8	23.4	22.9
Ohio and Northeast (3)	16.2	16.2	14.7
Subtotal	40.0	39.6	37.6
Total Mainline Transportation	162.9	167.7	170.2
Mont Belvieu Operations:			
LPGs	23.1	27.2	28.5
Total Product Deliveries	186.0	194.9	198.7

(1) Arkansas, Louisiana, Missouri and Texas.

(2) Illinois and Indiana.

(3) New York and Pennsylvania.

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 the Products Pipeline System also affect the demand for, and the mix of, the products delivered.

Refined products and LPGs deliveries over the last three years were as follows:

	Product Deliveries (MMBbls) Years Ended December 31,		
	2001	2000	1999
Refined Products Mainline Transportation:			
Gasoline	68.2	67.8	71.6
Jet Fuels	25.4	28.1	26.9
Middle Distillates (1)	28.1	26.6	28.4
MTBE(2)/Toluene	1.2	5.6	5.7
Subtotal	122.9	128.1	132.6
LPGs Mainline Transportation:			
Propane	32.8	33.1	30.8
Butanes	7.2	6.5	6.8
Subtotal	40.0	39.6	37.6
Total Mainline Transportation	162.9	167.7	170.2
Mont Belvieu Operations:			
LPGs	23.1	27.2	28.5
Total Product Deliveries	186.0	194.9	198.7

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

(2) Methyl tertiary butyl ether, a fuels additive, the use of which has largely been discontinued.

Refined Products Mainline Transportation

The 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. TE Products canceled its tariff for deliveries of MTBE into the Chicago market area on July 1, 1999, and canceled contract deliveries of MTBE at its marine terminal near Beaumont, Texas, effective April 22, 2001. The Partnership no longer transports MTBE through the Products Pipeline System.

The volume of refined petroleum products transported by the Products Pipeline System is directly affected by the demand for such products in the geographic regions the system serves. This market demand varies based upon the different end uses to which the refined products deliveries are applied. Demand for gasoline, which accounts for a substantial portion of the volume of refined products transported through the Products Pipeline System, depends upon price, prevailing economic conditions and demographic changes in the markets served. Demand for refined products used in agricultural operations 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 the Partnership's 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 revenues from period to period.

LPGs Mainline Transportation

The 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. Since LPGs demand is generally stronger in the winter months, the Products Pipeline System often operates at or near capacity during such time. Propane deliveries are generally sensitive to the weather and meaningful year-to-year variations have occurred and will likely continue to occur.

The Partnership's ability in its Downstream Segment to serve markets in the Northeast is enhanced by its propane import terminal at Providence, Rhode Island. This facility includes a 400,000-barrel refrigerated storage tank along with ship unloading and truck loading facilities. Effective May 2001, the Company entered into an agreement with DEFS to commit sole utilization of the Providence terminal to DEFS. The terminal is operated by the Partnership. During the year ended December 31, 2001, DEFS paid the Partnership $1.5 million pursuant to this agreement.

Mont Belvieu LPGs Storage and Pipeline Shuttle

A key aspect of the Products Pipeline System's LPGs business is its storage and pipeline asset base in the Mont Belvieu complex serving the fractionation, refining and petrochemical industries. The complex is the largest of its kind in the United States and provides substantial capacity and flexibility in the transportation, terminaling and storage of NGLs, LPGs, petrochemicals and olefins.

The Partnership's Downstream Segment has approximately 36 million barrels of LPGs storage capacity, including storage capacity leased to outside parties, at the Mont Belvieu complex. The Downstream Segment includes a Mont Belvieu 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.

In February 2000, the Partnership and Louis Dreyfus Plastics Corporation ("Louis Dreyfus") announced a joint marketing and development alliance. The Partnership's Mont Belvieu LPGs storage and transportation shuttle system services are jointly marketed by Louis Dreyfus and the Partnership. The purpose of the alliance 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. TE Products operates the facilities for the alliance. The alliance is a service-oriented, fee-based venture with no commodity trading activity. Under the alliance, Louis Dreyfus has invested $4.4 million for expansion projects at Mont Belvieu. The Partnership is required to reimburse this amount to Louis Dreyfus if the alliance is terminated by either Louis Dreyfus or the Partnership.

Other Operating Revenues

The Partnership's Downstream Segment also derives revenue from terminaling activities and other ancillary services associated with the transportation and storage of refined petroleum products and LPGs. From time to time, the Partnership sells excess product inventory.

Customers

The Downstream Segment's 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, 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 fuel source. Refineries constitute the Partnership's 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, 2001, the Downstream Segment had approximately 140 customers. Transportation revenues (and percentage of total revenues) attributable to the top 10 customers were $115 million (44%), $102 million (45%) and $105 million (47%), for the years ended December 31, 2001, 2000 and 1999, respectively. During 2001, no single customer accounted for 10% or more of the Downstream Segment's revenues.

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. The Partnership believes the 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. The Partnership faces competition from rail movements of LPGs from Sarnia, Ontario, Canada, and waterborne imports into New Hampshire.

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

Operations

The Partnership conducts business in its Upstream Segment through TCTM and its wholly-owned subsidiaries, which gather, transport, market and store crude oil, and distribute lubrication oils and specialty chemicals principally in Oklahoma, Texas and the Rocky Mountain region. The Partnership commenced its Upstream Segment business in connection with the acquisition of certain assets from DEFS in November 1998. The Partnership's Upstream Segment utilizes its asset base to aggregate crude oil and provide transportation and specialized services to its regional customers. The Partnership's Upstream Segment purchases crude oil at prevailing prices from producers at the wellhead, aggregates such crude oil into its equity owned pipelines or third party owned pipelines utilizing its truck fleet and transports the crude oil for ultimate sale to or exchange with its customers.

Margins in the Upstream Segment 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 operating revenues and operating expenses due to the significant fluctuations in revenues and expenses caused by variations in the level of marketing activity and prices for products marketed.

TCTM purchases crude oil and simultaneously establishes a margin by selling crude oil for physical delivery to third party users. The Partnership seeks to maintain a balanced marketing position until it makes physical delivery of the crude oil, thereby minimizing or eliminating exposure to price fluctuations occurring after the initial purchase. However, certain basis risks, the risk that price relationships between delivery points, classes of products or delivery periods will change, cannot be completely hedged or eliminated. The Partnership makes limited use of commodity derivative products for the purpose of speculating on price changes. Risk management policies have been established for the Partnership by the Company's Risk Management Committee to monitor and control market risks. The Risk Management Committee is comprised, in part, of senior executives of the Company. The Partnership had no commodity derivative contracts outstanding at December 31, 2001.

Volume information of TCTM's 100% owned pipeline systems and undivided joint interest pipelines for the years ended December 31, 2001, 2000 and 1999, is presented below (in thousands):

	Years Ended December 31,		
	2001	2000	1999
Total Barrels:			
Crude oil transportation	78,714	46,225	33,267
Crude oil marketing	159,477	107,607	96,252
Crude oil terminaling	121,932	56,473	—
Lubricants and chemicals (total gallons)	8,769	7,974	8,891

Properties

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

Crude Oil Pipeline	Partnership Ownership	Operator	Description
Red River System	100%	TEPPCO Crude Pipeline ("TCPL") (1)	1,690 miles of pipeline; 1,484,000 barrels storage — North Texas to South Oklahoma
South Texas System	100%	TCPL	690 miles of pipeline; 740,000 barrels 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 TCTM's Midland, Texas terminal
Seaway	50% general partnership interest (2)	TCPL	500-mile, 30-inch diameter pipeline — Texas Gulf Coast to Cushing, Oklahoma
Rancho	25% joint ownership	Equilon Pipeline Company, LLC	400-mile, 24-inch diameter pipeline — West Texas to Houston, Texas
Basin	13% joint ownership	Equilon Pipeline Company, LLC	416-mile pipeline — Permian Basin (New Mexico and Texas) to Cushing, Oklahoma

(1) TCPL is a wholly-owned subsidiary of TCTM.

(2) TCPL's participation in revenues and expenses of Seaway vary as described below in "Partnership Interest in Seaway Crude Pipeline."

None of these pipelines or systems is subject to any encumbrance from a mortgage or other secured debt.

The majority of the Red River System crude oil is delivered to Cushing, Oklahoma via connecting 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 connects gathering systems to TCTM's Midland, Texas terminal. Other crude oil assets, located primarily in Texas and Louisiana, consist of 344 miles of pipeline and 295,000 barrels of storage capacity.

Partnership Interest in Seaway Crude Pipeline

Seaway Crude Pipeline Company ("Seaway") is a partnership between TCTM and Phillips. In July 2000, the Partnership acquired its 50-percent ownership interest in Seaway from ARCO Pipe Line Company ("ARCO"), a wholly-owned subsidiary of Atlantic Richfield Company. The Partnership 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. Two 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. 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 tank farms 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 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, the Partnership will receive 80% of revenue and expense of Seaway. From June 2002 until May 2006, the Partnership will receive 60% of revenue and expense of Seaway. Thereafter, the Partnership will receive 40% of revenue and expense of Seaway.

Line Transfers, Pumpovers and Other

The Partnership's Upstream Segment provides trade documentation services to its customers, primarily at Cushing and Midland. TCTM 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 TCTM's customers of NYMEX open-interest crude oil contracts. 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 the Partnership's consolidated statements of income.

The line transfer services also attract physical barrels to TCTM'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 TCTM's custody. TCTM owns and operates storage facilities 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 the Partnership's consolidated statements of income and represents the crude oil terminaling component of margin. The line transfer and pumpover operations were acquired from ARCO in July 2000.

Through its subsidiary, Lubrication Services, L.P. ("LSI"), TCTM 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, Oklahoma, Kansas, New Mexico, Texas, and Louisiana.

Customers

TCTM 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. During 2001, no single customer accounted for 10% or more of the margin of the Partnership's Upstream Segment. The Company does not believe the loss of any single customer would have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Partnership.

Competition

The most significant competitors in pipeline operations in the Partnership's 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 its 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 has intensified competition among gatherers and marketers.

A significant portion of the growth in the Partnership's Upstream Segment has occurred through acquisitions of pipeline gathering systems. The Partnership's acquisitions in this segment have provided increased efficiencies for the gathering and transportation of crude oil with its existing pipeline systems as well as expansion into new market areas. The Partnership experiences competition from other gatherers and marketers in the 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, which may decrease the amount of potential acquisitions of crude gathering systems available to the Partnership.

Credit Policies and Procedures

As crude oil or lubrication oils are marketed, the Partnership must determine the amount, if any, of credit to be extended to any given customer, particularly in the Partnership's Upstream Segment, where transported volumes are typically sold rather than transported for a fee. Due to the nature of individual sales transactions, risk of non-payment and non-performance by customers is a major consideration in the Partnership's business. The Partnership manages its exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. The Partnership utilizes letters of credit and guarantees for certain of its receivables. However, these procedures and policies may not fully eliminate customer credit risk. During the years ended 1999, 2000 and 2001, no reserves were necessary to write-off uncollectible receivables of the Upstream Segment.

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

The Partnership conducts business in its Midstream Segment through TEPPCO Colorado, LLC ("TEPPCO Colorado"), which fractionates NGLs, TCTM and its wholly-owned subsidiaries, which transport NGLs through its NGL pipelines, and Jonah Gas Gathering Company ("Jonah"), which gathers natural gas.

On December 31, 2000, the Company completed an acquisition of certain pipeline assets from DEFS for $91.7 million, which included $0.7 million of acquisition related costs. The purchase included two NGL pipelines in East Texas: the Panola Pipeline, a pipeline from Carthage, Texas, to Mont Belvieu, Texas, and the San Jacinto Pipeline, a pipeline from Carthage to Longview, Texas. The pipelines originate at DEFS' East Texas Plant Complex in Panola County, Texas. The acquisition of the assets was accounted for under the purchase method of accounting.

The Partnership's Midstream Segment acquired all of the partnership interests of Jonah from Alberta Energy Company, effective September 30, 2001, by subsidiaries of the Partnership. The original purchase price totaled $359.8 million. An additional $7.2 million was accrued at December 31, 2001, for final purchase price adjustments related primarily to construction projects in progress at the time of closing. The acquisition was accounted for under the purchase method of accounting. Accordingly, the results of operations of the acquisition are included in the Partnership's consolidated financial statements in the fourth quarter of 2001. The assets of Jonah are managed and operated by DEFS under a contract arrangement. Jonah and its assets are not subject to any encumbrances from mortgages or other secured debt.

In connection with the acquisition of Jonah, the Partnership assumed responsibility for the completion of an ongoing expansion of the Jonah Gas Gathering System ("Jonah System") at a cost of approximately $25.0 million. The expansion, which is expected to be completed by the end of March 2002, will increase the capacity of the Jonah System by 62%, from approximately 450 million cubic feet per day ("MMcf/day"), to approximately 730 MMcf/day.

In February 2002, a producer on the Jonah System notified Alberta Energy Company that it has a right to acquire all or a portion of the assets comprising the Jonah System. This claim is based upon an alleged right of first refusal contained in a gas gathering agreement between the producer and Jonah. Subsidiaries of Alberta Energy Company have agreed to indemnify the Partnership against losses resulting from the breach of representations concerning the absence of third party rights in connection with the acquisition of the entity that owns the Jonah System. The Partnership believes that it has adequate legal defenses to the producer's claim and that no right of first refusal on any of the underlying Jonah System assets has been triggered.

Revenues of the Partnership's Midstream Segment are earned from fractionation of NGLs in Colorado, transportation of NGLs and gathering fees based on the volume and pressure of natural gas gathered, and also from sales of condensate on the Jonah System. TEPPCO Midstream has multiple long-term contracts with producers connected to the Jonah System. The Partnership cannot influence or control the operation or development of the gas fields served by the Jonah System. Production levels may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations. The Partnership does not take title to the natural gas gathered, NGLs transported or NGLs fractionated. Accordingly, the results of operations of the Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs. It is expected that

Midstream Segment revenues and cash flows will increase from historical levels as the system capacity expansion becomes operational.

Volume information for the years ended December 31, 2001, 2000 and 1999, is presented below:

	Years Ended December 31,		
	2001	2000	1999
Gathering — Natural Gas (billion cubic feet (“Bcf”))	45.5	—	—
Transportation — NGLs (thousand barrels)	21,538	5,201	4,580
Fractionation — NGLs (thousand barrels)	4,078	4,078	3,819
Sales — Condensate (thousand barrels)	16.2	—	—

The Jonah Gas Gathering System

The Jonah System consists of approximately 350 miles of pipelines ranging in size from four to 20 inches in diameter, four compressor stations with an aggregate of approximately 21,200 horsepower and related metering facilities. Gas gathered on the Jonah System is collected from approximately 375 producing wells in the Green River Basin in southwestern Wyoming, which is one of the most prolific natural gas basins in the United States. A component of the system is a processing facility that extracts condensate prior to delivery of natural gas to DEFS’ Overland Trail Transmission system and Questar. Gas is 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 the Overland Trail Transmission system, Kern River, Northwest, Colorado Interstate Gas and Questar.

NGL Transportation

The NGL pipelines of the Midstream Segment are located along the Texas Gulf Coast. They are all wholly-owned and operated by subsidiaries of the Partnership. Information concerning these NGL pipelines is set forth in the following table:

NGL Pipeline	Capacity (barrels/day)	Description
Dean	20,000	338 miles of pipeline — South Texas to Mont Belvieu, Texas
Panola	38,000	189 miles of pipeline — Carthage, Texas to Mont Belvieu, Texas
San Jacinto	11,000	34 miles of pipeline — Carthage, Texas to Longview, Texas
Wilcox	7,000	90 miles of pipeline — Southeast Texas

None of these pipelines is subject to any encumbrance from a mortgage or other secured debt.

The Wilcox NGL Pipeline transports NGLs for DEFS from two of their natural gas processing plants. The Wilcox NGL Pipeline is currently supported by a throughput agreement with DEFS through 2005. The Panola Pipeline and San Jacinto Pipeline were purchased on December 31, 2000, from DEFS and originate at DEFS’ East Texas Plant Complex in Panola County, Texas.

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 is delivered into major interstate gas pipelines for delivery primarily to markets along the West Coast. NGL sales are primarily to major integrated oil and gas companies and independent refiners.

At December 31, 2001, the Midstream Segment had 16 customers. Revenues attributable to the top 10 customers were $37.0 million (99%) for the year ended December 31, 2001, of which DEFS, Enron Corp. and Alberta Energy Company accounted for approximately 61%, 13% and 11% of revenues of the Partnership's Midstream Segment, respectively. At December 31, 2000, the Midstream Segment had three customers. Revenues attributable to the three customers were $14.5 million, of which DEFS and Enron Corp. accounted for 60% and 39% of revenues of the Midstream Segment, respectively. At December 31, 1999, the Midstream Segment had two customers. Revenues attributable to the two customers were $13.5 million, of which DEFS and Enron Corp. accounted for 63% and 37% of revenues of the Midstream Segment, respectively.

The Partnership manages its exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. The Partnership utilizes letters of credit and guarantees for certain of its receivables. However, these procedures and policies may not fully eliminate customer credit risk. The bankruptcy of Enron Corp. and certain of its subsidiaries in December 2001 has made doubtful the collection of approximately $4.3 million of transportation deficiency payments by the Partnership.

Competition

The most significant competition for the NGL pipeline operations portion of the Partnership's Midstream Segment comes primarily from proprietary pipelines owned and operated by major oil and gas companies or 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, knowledge of products and markets, and market-responsive transportation rates.

The majority of the recently reported growth in the Midstream Segment is due to the acquisition of the Jonah Gas Gathering System in Wyoming. 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 Partnership's Jonah System in Wyoming are both relatively young producing areas, characterized by long-lived production profiles and many years of significant growth potential ahead. The Partnership expects to aggressively market this system by obtaining contracts to gather additional natural gas supplies.

Competition in the natural gas gathering portion of the Partnership's Midstream Segment is based in large part on reputation, efficiency, system reliability, system capacity, and market responsive pricing arrangements. 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 the Partnership's 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 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 a Partnership gathering system declines, revenues from such operations would also be adversely affected. If such declines are sustained or substantial, then the Partnership could experience a material adverse effect on its financial position, results of operations or cash flows.

Title to Properties

The Partnership believes it has satisfactory title to all of its 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. In February 2002, a producer on the Jonah System notified Alberta Energy Company that it has a right to acquire all or a portion of the assets comprising Jonah. See Items 1 and 2. Business and Properties, “Midstream Segment — Gathering of Natural Gas, Fractionation of NGLs and Transportation of NGLs” for a more detailed discussion of the matter. The Partnership believes none of these liabilities materially affects the value of its properties or the Partnership’s interest therein or will materially interfere with their use in the operation of the Partnership’s business.

Capital Expenditures

Capital expenditures, excluding acquisitions, by the Partnership totaled $107.6 million for the year ended December 31, 2001. Revenue generating projects include those projects which expand service into new markets or expand capacity into current markets. Maintenance capital spending includes projects required by regulatory agencies or required life-cycle replacements. System upgrade projects improve operational efficiencies or reduce cost. The Partnership capitalizes interest costs incurred during the period that construction is in progress. The following table identifies capital expenditures by segment for the year ended 2001 (in millions):

	Revenue Generating	Maintenance Capital	System Upgrades	Capitalized Interest	Total
Downstream Segment	$62.2	$12.7	$3.0	$3.5	$ 81.4
Upstream Segment	5.0	4.7	2.8	0.4	12.9
Midstream Segment	12.1	1.1	—	0.1	13.3
Total	$79.3	$18.5	$5.8	$4.0	$107.6

Revenue generating capital spending by the Downstream Segment included $35.5 million used to expand the Partnership’s capacity to support the receipt connection point at Beaumont, Texas, and delivery location at Creal Springs, Illinois, with Centennial and $17.4 million used to construct connections and related facilities for the petrochemical pipelines at Mont Belvieu. Revenue generating capital spending of the Midstream Segment related to the Dean pipeline and the ongoing expansion of the Jonah System that was assumed by the Partnership upon the purchase on September 30, 2001.

The Partnership estimates that capital expenditures, excluding acquisitions, for 2002 will be approximately $74 million (which includes $4 million of capitalized interest). Approximately $31 million is expected to be used for revenue generating projects. Approximately $27 million is expected to be used for maintenance capital spending and approximately $12 million for system upgrade projects. Revenue generating projects will include the completion of facilities to support the receipt and delivery locations with Centennial, the completion of the Jonah System expansion, additional well connections to the Jonah System and other projects to expand service capabilities of the Partnership. Approximately $4.9 million of maintenance capital spending is expected to be used for pipeline rehabilitation projects to comply with regulations enacted by the United States Department of Transportation Office of Pipeline Safety (“OPS”). The Partnership continually reviews and evaluates potential capital improvements and expansions that would be complementary to its present business segments. These expenditures can vary greatly depending on the magnitude of these transactions by the Partnership. Capital expenditures may be financed through internally generated funds, debt or the issuance of additional Limited Partner Units.

Regulation

The Partnership’s interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act (“ICA”), the Energy Policy Act of 1992 (“Act”) and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate oil pipeline rates be posted publicly and that these rates be “just and reasonable” and nondiscriminatory.

Rates of interstate oil pipeline companies, like the Partnership, are currently regulated by the FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the change from year to year in the Producer Price Index for finished goods less 1% (“PPI Index”). In the alternative, interstate 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 the oil pipeline company that the rate is acceptable (“Settlement Rates”).

On May 11, 1999, TE Products filed an application with the FERC requesting permission to charge Market-Based Rates for substantially all refined products transportation tariffs. On July 31, 2000, the FERC issued an order granting TE Products Market-Based Rates in certain markets and set for hearing TE Products’ application for Market-Based Rates in certain destination markets and origin markets. After the matter was set for hearing, TE Products and the protesting shippers entered into a settlement agreement resolving their respective differences. On April 25, 2001, the FERC issued an order approving the offer of settlement. As a result of the settlement, TE Products recognized approximately $1.7 million of previously deferred transportation revenue in the second quarter of 2001. As a part of the settlement, TE Products withdrew the application for Market-Based Rates to the Little Rock, Arkansas, Arcadia and Shreveport-Arcadia, Louisiana, destination markets, which are currently subject to the PPI Index. As a result, the Partnership made refunds of approximately $1.0 million in the third quarter of 2001 for those destination markets.

Effective July 1, 1999, TE Products established Settlement Rates with certain shippers of LPGs under which the rates in effect on June 30, 1999, would not be adjusted for a period of either two or three years. Other LPGs transportation tariff rates were reduced pursuant to the PPI Index (approximately 1.83%), effective July 1, 1999.

In a 1995 decision involving an unrelated oil pipeline limited partnership, the FERC partially disallowed the inclusion of income taxes in that partnership’s cost of service. In another FERC proceeding involving a different oil pipeline limited partnership, the FERC held that the oil pipeline limited partnership may not claim an income tax allowance for income attributable to non-corporate limited partners, both individuals and other entities. These FERC decisions do not affect the Partnership’s current rates and rate structure because the Partnership does not use the cost of service methodology to support its rates. However, the FERC decisions might become relevant to the Partnership should it (i) elect in the future to use the cost-of-service methodology or (ii) be required to use such methodology to defend initial rates or its indexed rates against a shipper protest alleging that an indexed rate increase substantially exceeds actual cost increases. Should such circumstances arise, there can be no assurance with respect to the effect of such precedents on the Partnership’s rates in view of the uncertainties involved in this issue.

While the FERC does not directly regulate the natural gas gathering operations of the Jonah System, federal regulation, directly or indirectly, influences the parties that gather natural gas on the Jonah System. The Jonah System is exempt from FERC regulation under the Natural Gas Act of 1938 since it is an intrastate gas gathering system rather than an interstate transmission pipeline. However, FERC regulation still significantly affects the Midstream Segment. In recent years, FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue the pro-competition policy 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

The operations of the Partnership are subject to federal, state and local laws and regulations governing the discharge of materials into the environment otherwise relating to environmental protection. 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 the Partnership believes its operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and there can be no assurance 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 its operations, could result in substantial costs and liabilities to the Partnership. The Company does not anticipate that changes in environmental laws and regulations will have a material adverse effect on the Partnership's 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 refined petroleum products is an inherent risk within the petroleum pipeline industry. To the extent that groundwater contamination requiring remediation exists along its pipeline systems as a result of past operations, the Partnership believes any such contamination could be controlled or remedied without having a material adverse effect on the financial condition of the Partnership, but such costs are site specific, and there can be no assurance 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 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 the Partnership 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 the Partnership operates. Such permits may require the Partnership to monitor and sample the storm water run-off.

Air Emissions

The operations of the Partnership 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 operations of the Partnership to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some of the Partnership's 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, one federal operating permit (a "Title V" permit) is 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. The Partnership has completed applications for the facilities for which these regulations apply.

Risk Management Plans

The Partnership is 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 Regulation" following) to minimize the offsite consequences of catastrophic releases. The regulation requires a regulated source, in excess of threshold quantities, develop and implement a risk management program that includes a five-year accident history, an offsite consequence analyses, a prevention program, and an emergency response program. The Company believes the operating expenses of the RMP regulations will not have a material adverse effect on the Partnership's financial position, results of operations or cash flows.

Solid Waste

The Partnership generates hazardous and non-hazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. 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 the operating expenses of the Partnership as well as the industry in general. The Partnership utilizes waste minimization and recycling processes to reduce the volume of its waste. The Partnership currently has one permitted on-site waste water treatment facility. Operating expenses of this facility has not had a material adverse effect on the financial position, results of operations or cash flows of the Partnership.

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 from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of its ordinary operations, the Partnership's pipeline system generates wastes that may fall within CERCLA's definition of a "hazardous substance." In the event a disposal facility previously used by the Partnership requires clean up in the future, the Partnership may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

In December 1999, the Company was notified by the EPA of potential liability for alleged waste disposal at Container Recycling, Inc., located in Kansas City, Kansas. The Company was also asked to respond to an EPA Information Request. The Company's response to the information request has been filed with the EPA Region VII office. Based on information the Company has received from the EPA, as well as through its internal investigations, the Company is pursuing dismissal from this matter.

Other Environmental Proceedings

In 1994, the Partnership and the Indiana Department of Environmental Management (“IDEM”) entered into an Agreed Order that resulted in the implementation of a remediation program for groundwater contamination attributable to the Partnership’s operations at the Seymour, Indiana, terminal. A Feasibility Study, which includes the Partnership’s proposed remediation program, was approved by IDEM in 1999. IDEM is expected to issue a Record of Decision formally approving the remediation program. After the Record of Decision is issued, the Partnership will enter into a subsequent Agreed Order for the continued operation and maintenance of the remediation program. The Partnership has an accrued liability of $0.6 million at December 31, 2001, for future remediation costs at the Seymour terminal. In the opinion of the Company, the completion of the remediation program will not have a future material adverse effect on the Partnership’s financial condition, results of operations or cash flows.

In 1994, the Partnership was issued a compliance order from the Louisiana Department of Environmental Quality (“LDEQ”) relative to environmental contamination at the Partnership’s Arcadia, Louisiana, facility. This contamination may be attributable to the operations of the Partnership, as well as adjacent petroleum terminals operated by other companies. In 1999, the Partnership’s Arcadia facility and the adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this containment phase. In the opinion of the Company, the completion of the remediation program that is proposed by the Partnership will not have a future material adverse effect on the Partnership’s financial condition, results of operations or cash flows.

During 2001, the Partnership accrued $8.6 million to complete environmental remediation activities at certain of the sites owned by TCTM and its subsidiaries. In establishing this accrual, the Partnership expensed $4.4 million for these environmental remediation costs and recorded a receivable of $4.2 million for the remainder. The receivable is based on a contractual indemnity obligation for specified environmental liabilities owed by DEFS to the Partnership in connection with the Partnership’s acquisition of the Upstream Segment from DEFS in November 1998. Under this indemnity obligation, the Partnership is responsible for the first $3.0 million in specified environmental liabilities, with DEFS becoming responsible for those environmental liabilities in excess of $3.0 million, up to a maximum amount of $25.0 million. At December 31, 2001, an accrual of $6.4 million remains outstanding related to TCTM environmental remediation activities. The majority of the indemnified costs relate to remediation activities at the Velma crude oil site in Stephens County, Oklahoma, attributable to operations prior to the Partnership’s acquisition of the Upstream Segment. Remediation activities at the Velma crude oil site are being conducted according to a work plan approved by the Oklahoma Corporation Commission. In the opinion of the Company, the completion of remediation programs associated with this release will not have a future material adverse effect on the Partnership’s financial condition, results of operations or cash flows.

Safety Regulation

The Partnership is 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 its 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 make certain reports and provide information as required by the Secretary of Transportation. It is anticipated that the HLPSA will be reauthorized in 2002.

The Partnership is subject to the OPS 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, and amends certain training requirements in existing regulations. A written qualification program was completed in April 2001, and individuals performing a covered task must be qualified by October 2002.

The Partnership is also subject to the OPS Integrity Management regulations which specifies 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 highly populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires an Integrity Management Program (“IMP”) be developed 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 OPS regulations, the Partnership has identified its HCA pipeline segments and will develop an IMP by March 31, 2002. The regulations require that initial HCA baseline integrity assessments are conducted within seven years, with all subsequent assessments conducted on a five-year cycle. The Partnership will evaluate each pipeline segment’s integrity by analyzing available information and develop a range of potential impacts resulting from a release to a HCA. The Partnership is currently developing cost estimates related to its baseline integrity assessments.

The Partnership is also subject to the requirements of the federal OSHA and comparable state statutes. The Partnership believes it is 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 the Partnership to organize and disclose information about the hazardous materials used in its operations. Certain parts of this information must be reported to employees, state and local governmental authorities, and local citizens upon request. The Partnership is 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. The Partnership utilizes certain covered processes and maintains 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. The Partnership believes it is in material compliance with the PSM regulations.

In general, the General Partner expects to increase the expenditures of the Partnership 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, the Company does not believe that they will have a future material adverse effect on the Partnership’s financial condition, results of operations or cash flows.

Employees

The Partnership does not have any employees, officers or directors. The General Partner is responsible for the management of the Partnership and Operating Partnerships. As of December 31, 2001, the General Partner had 919 employees.

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

General

The following information is provided to facilitate increased understanding of the 2001, 2000 and 1999 consolidated financial statements and accompanying notes of the Partnership listed in the Index to Financial Statements on page F-1 of this report. Accounting policies that are among the most critical to the portrayal of the Partnership’s financial condition and results of operations are discussed under “Critical Accounting Policies.” Material period-to-period variances in the consolidated statements of income are discussed under “Results of Operations.” The “Financial Condition and Liquidity” section analyzes cash flows and financial position. Discussion included in “Other Considerations” addresses trends, future plans and contingencies that are reasonably likely to materially affect future liquidity or earnings.

The Partnership operates and reports 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, fractionation of NGLs and transportation of NGLs.

The Partnership's reportable segments offer different products and services and are managed separately because each requires different business strategies. Each of the subsidiaries of the Partnership that are limited partnerships is managed by TEPPCO GP, a wholly-owned subsidiary of the Partnership that acts as managing general partner with a 0.001% general partner interest.

Effective January 1, 2002, the Partnership realigned its three business segments in order to separate and better measure the performance of its natural gas and NGL operations from its crude oil operations. The fractionation of NGLs, which was previously reflected as part of the Downstream Segment, was shifted to the Midstream Segment. The operation of NGL pipelines, which was previously reflected as part of the Upstream Segment, was also shifted to the Midstream Segment. The year-to-year comparisons have been adjusted to conform to the current presentation.

The Downstream Segment revenues are derived from the transportation and storage of refined products and LPGs, storage and short-haul shuttle transportation of LPGs at the Mont Belvieu complex, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Labor and electric power costs comprise the two largest operating expense items of the Downstream Segment. Operations are somewhat seasonal with higher revenues generally realized during the first and fourth quarters of each year. 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.

The Upstream Segment revenues are earned from the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along its pipeline systems, or from third party pipeline systems, and arranging the necessary logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users.

On July 20, 2000, the Partnership completed an acquisition of assets from ARCO for $322.6 million, which included $4.1 million of acquisition-related costs other than the purchase price. An additional $11.0 million was paid in October 2001, for final post-closing adjustments. The purchased assets included ARCO's 50-percent voting interest in Seaway. The Partnership assumed ARCO's role as operator of this pipeline. The Company also acquired ARCO's crude oil terminal facilities in Cushing and Midland, including the line transfer and pumpover business at each location, an undivided ownership interest in both the Rancho Pipeline and the Basin Pipeline, both of which are operated by another joint owner, and the receipt and delivery pipelines known as the West Texas Trunk System, located around the Midland terminal. The transaction was accounted for under the purchase method of accounting. The results of operations of the assets acquired have been included in the Upstream Segment since the purchase on July 20, 2000.

The Midstream Segment revenues are earned from gathering of natural gas, fractionation of NGLs in Colorado and transportation of NGLs. On December 31, 2000, the Company completed an acquisition of certain pipeline assets from DEFS for $91.7 million, which included $0.7 million of acquisition related costs. The purchase included two NGL pipelines in East Texas: the Panola Pipeline, a pipeline from Carthage, Texas, to Mont Belvieu, Texas, and the San Jacinto Pipeline, a pipeline from Carthage to Longview, Texas. The pipelines originate at DEFS' East Texas Plant Complex in Panola County, Texas. The acquisition of the assets was accounted for under the purchase method of accounting.

The Midstream Segment also includes operations acquired on September 30, 2001, when the Partnership acquired Jonah from Alberta Energy Company for $359.8 million. An additional $7.2 million was accrued at December 31, 2001, for final purchase adjustments related primarily to construction projects in progress at the time of closing. The acquisition was accounted for under the purchase method of accounting. Accordingly, the results of operations of the acquisition are included in the Partnership's consolidated financial statements in the fourth quarter of 2001. The Jonah assets are managed and operated by DEFS under a contract arrangement.

Critical Accounting Policies

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Changes in these estimates could materially affect the financial condition, results of operations or cash flows.

Environmental Costs

The Partnership accrues 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 fines, damages and other costs, when estimable. The balance of accrued undiscounted environmental liabilities are monitored on a regular basis by management. Liabilities for environmental costs at a specific site are initially recorded when the Partnership's liability for such costs, including direct internal and legal 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 the Partnership's 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. For information concerning environmental regulation and environmental costs and contingencies, see Item 1 and 2. Business and Properties — "Environmental Matters" in this Report.

Property, Plant and Equipment

Statement of Financial Accounting Standards ("SFAS") No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of* requires that an entity review long-lived assets, including property, plant and equipment, whenever events occur that indicate that the book value of an asset may not be recoverable in the future. In August 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* SFAS 144 supercedes SFAS 121, but retains its fundamental provisions for reorganizing and measuring impairment losses on long-lived assets held for use and long-lived assets to be disposed of by sale. During the second quarter of 2001, Pennzoil-Quaker State Company ("Pennzoil") sold its Shreveport, Louisiana, refinery and canceled refined products production. Pennzoil and TE Products negotiated a settlement of $18.9 million to terminate a long-term transportation agreement from the Shreveport origin point on the Products Pipeline System. Under the transportation agreement, Pennzoil had a throughput commitment of 25,000 barrels per day. The Partnership is pursuing various alternatives related to the reduced receipt volumes including making system changes to allow for bi-directional product flow to make deliveries into the Shreveport market area. The Partnership has evaluated the impact of the contract termination on the pipeline segment from Shreveport to El Dorado, Arkansas, in accordance with SFAS 144. The evaluation did not result in an impairment of the carrying value of the related transportation assets. The termination payment was recorded as refined products transportation revenue in 2001. However, if alternative revenue sources are not realized on this pipeline segment, an impairment may be recorded, which could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Intangible Assets

On September 30, 2001, the Partnership completed the purchase of all of the partnership interests of Jonah from Alberta Energy Company for $359.8 million. An additional $7.2 million was accrued at December 31, 2001, for final purchase adjustments related primarily to construction projects in progress at the time of closing. In connection with this acquisition, the Partnership assumed contracts that dedicate future production from natural gas wells in the Green River Basin in the State of Wyoming. The Partnership assigned $222.8 million of the purchase price to these production contracts based upon a fair value appraisal at the time of closing. The value assigned to intangible assets are amortized over the expected lives of the contracts (approximately 16 years) in proportion to the timing of the expected contractual volumes. On an annual basis, the Partnership will update production estimates of the natural gas wells and reassess the remaining useful life of the contract assets. Changes in the estimated remaining production could negatively impact the timing of amortization expense reported for future periods.

Results of Operations

Summarized below is financial data by business segment (in thousands):

	Years Ended December 31,		
	2001	2000	1999
Operating revenues:			
Downstream Segment	$ 264,233	$ 229,234	$ 222,915
Midstream Segment	37,242	14,462	13,478
Upstream Segment	3,255,260	2,844,245	1,698,490
Intercompany eliminations	(322)	—	—
Total operating revenues	3,556,413	3,087,941	1,934,883
Operating income:			
Downstream Segment	117,676	85,441	84,880
Midstream Segment	15,823	8,886	8,302
Upstream Segment	17,490	13,698	6,908
Total operating income	150,989	108,025	100,090
Earnings before interest:			
Downstream Segment	118,064	87,092	86,351
Midstream Segment	15,897	9,123	8,502
Upstream Segment	38,027	26,373	7,433
Total earnings before interest	171,988	122,588	102,286
Interest expense	(66,057)	(48,982)	(31,563)
Interest capitalized	4,000	4,559	2,133
Minority interest	(800)	(789)	(736)
Net income	$ 109,131	$ 77,376	$ 72,120

The results for the year ended 2001 reflect the acquisition of Jonah on September 30, 2001. The results for the year ended 2000 reflect the increased operations in the Upstream Segment resulting from the acquisition of the ARCO assets in July 2000, which results were impacted in 2001 as a result of having a full year of operations attributed to the former ARCO assets.

Following is a detailed analysis of the results of operations, discussing the reasons for changes in results, by each operating segment of the Partnership.

Table of Contents

Downstream Segment

Volume and average tariff information for 2001, 2000 and 1999 is presented below:

	Years Ended December 31,			Percentage Increase (Decrease)	
	2001	2000	1999	2001	2000
	(in thousands, except tariff information)				
Volumes Delivered					
Refined products	122,947	128,151	132,642	(4)%	(3)%
LPGs	39,957	39,633	37,575	1%	5%
Mont Belvieu operations	23,122	27,159	28,535	(15)%	(5)%
Total	186,026	194,943	198,752	(5)%	(2)%
Average Tariff per Barrel					
Refined products	$ 0.98(1)	$ 0.93	$ 0.93	5%	—
LPGs	1.95	1.86	1.80	5%	3%
Mont Belvieu operations	0.18	0.16	0.16	13%	—
Average system tariff per barrel	$ 1.09	$ 1.01	$ 0.98	8%	3%

(1) Excludes $18.9 million received from Pennzoil for canceled transportation agreement discussed below.

2001 Compared to 2000

For the year ended 2001, the Downstream Segment reported earnings before interest of $118.1 million, compared with earnings before interest of $87.1 million for the year ended 2000. The $31.0 million increase in earnings before interest was primarily due to a $35.0 million increase in operating revenues, partially offset by a $2.8 million increase in costs and expenses, $1.1 million in losses from equity investments and a $0.1 million decrease in other income — net. Factors influencing these variances are described below.

Refined products transportation revenues increased $20.0 million for the year ended 2001, compared with 2000, primarily due to $18.9 million of revenue recognized on the canceled transportation agreement with Pennzoil and the recognition of $1.7 million of previously deferred revenue related to the approval of Market-Based Rates during the second quarter of 2001. See further discussion regarding these factors included in “Other Considerations.” These increases were partially offset by a 4% decrease in refined products volumes delivered. Deliveries of MTBE decreased 4.3 million barrels as a result of the expiration of contract deliveries to the Partnership’s marine terminal near Beaumont, Texas, in April 2001. As a result of the contract expiration, the Partnership no longer transports MTBE through its Products Pipeline System. Jet fuel volumes decreased 2.7 million barrels, or 10%, due to reduced air travel demand in the Midwest market areas. The total refined products volume decrease was partially offset by increased distillate demand in the South-Central market areas and increased distillate deliveries at a third-party terminal in Houston, Texas. The refined products average rate per barrel increased 5% from the prior-year period primarily due to an increased percentage of long-haul volumes delivered in 2001.

LPGs transportation revenues increased $3.9 million for the year ended 2001, compared with 2000, primarily due to increased propane deliveries in the Midwest that resulted from favorable price differentials of Gulf Coast propane compared with competing Midwest supply sources. Additionally, increased feedstock demand resulted in higher deliveries of isobutane in the Chicago market area. Short-haul deliveries of propane along the upper Texas Gulf Coast decreased 29% from the prior year due to lower petrochemical feedstock demand and operational problems at a petrochemical facility served by the Partnership. The LPGs average rate per barrel increased 5% from the prior year as a result of an increased percentage of long-haul deliveries to the upper Midwest market areas.

Revenues generated from Mont Belvieu operations increased $0.8 million during the year ended 2001, compared with 2000, as a result of increased loading fees, brine service revenue and butane segregation charges, partially offset by lower contract storage revenue. Mont Belvieu shuttle deliveries decreased 15% during the year ended 2001, compared with 2000, due to reduced propane and butane demand for petrochemical feedstock along the upper Texas Gulf Coast. The Mont Belvieu average rate per barrel increased in 2001 as a result of increased non-contract deliveries, which generally carry higher rates.

Other operating revenues increased $10.3 million during the year ended 2001, compared with 2000, primarily due to an $8.9 million increase in contract petrochemical delivery revenue, which started during the fourth quarter of 2000, increased refined products loading fees, increased propane deliveries at the Providence, Rhode Island, import facility and increased gains on product sales. These increases were partially offset by losses incurred as a result of exchanging products at different geographic points of delivery to position product in the Midwest market area.

Costs and expenses increased $2.8 million for the year ended 2001, compared with 2000, comprised of a $2.1 million increase in operating, general and administrative expenses, a $1.2 million increase in operating fuel and power expense and a $1.0 million increase in depreciation and amortization expense, partially offset by a $1.5 million decrease in taxes — other than income taxes. The increase in operating, general and administrative expenses was primarily due to increased employee benefit costs, increased supplies and services and environmental remediation expenses, partially offset by the March 2000 write-off of project evaluation costs related to the proposed pipeline construction from Beaumont, Texas, to Little Rock, Arkansas, and decreased product measurement losses. Operating fuel and power expense increased as a result of higher rates charged by electric utilities and increased long-haul volumes delivered. The increase in depreciation expense from the prior year period resulted from assets placed in service during the fourth quarter of 2000. The decrease in taxes — other than income taxes resulted from actual property taxes being lower than previously estimated.

Net loss from equity investments totaled $1.1 million during the year ended 2001 due primarily to pre-operating expenses of Centennial. Other income — net decreased $0.1 million during the year ended 2001, compared with 2000, due primarily to lower interest income earned on cash investments.

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 has in recent years 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. Weather conditions, governmental policy and crop prices affect the demand for refined products used in agricultural operations. Demand for jet fuel, which has in recent years accounted for almost 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 and will likely continue to occur.

2000 Compared to 1999

For the year ended 2000, earnings before interest of the Downstream Segment increased $0.7 million compared with 1999 primarily due to a $6.3 million increase in operating revenues, partially offset by a $5.8 million increase in costs and expenses. Factors influencing these variances are described below.

Refined products transportation revenues decreased $3.7 million for the year ended 2000, compared with 1999, as a result of a 3% decrease in total refined products volumes delivered. Motor fuel volumes delivered decreased by 2.5 million barrels and distillate volumes delivered decreased by 1.8 million barrels due primarily to a local refinery expansion in the West Memphis market and unfavorable price differentials in the Midwest market area. Natural gasoline volumes delivered declined 1.3 million barrels due primarily to the expiration of a contract in late 1999 for deliveries to the Chicago area, along with unfavorable processing and blending economics in the Chicago market area. These decreases were primarily offset by a 1.2 million barrel increase in jet fuel volumes delivered due to continued strong demand in the Chicago market area and at the Cincinnati airport that is supplied by the Partnership. The Partnership deferred recognition of approximately $1.5 million of revenue during the year ended 2000, with respect to potential refund obligations for rates charged in excess of the PPI Index while its application for Market-Based Rates was under review by the FERC.

LPGs transportation revenues increased $6.2 million for the year ended 2000, compared with 1999, due to a 5% increase in volumes delivered and a 3% increase in the average LPGs tariff per barrel. Colder winter weather during the first and fourth quarters of 2000, coupled with lower customer storage levels contributed to a 1.2 million barrel increase in propane volumes delivered in the Northeast market area and a 0.9 million barrel increase in propane volumes delivered in the Midwest market area. Increased refinery demand in the Northeast market area resulted in a 0.2 million barrel increase in butane volumes delivered. The larger percentage of long-haul deliveries during 2000 resulted in a 3% increase in the average LPGs tariff per barrel.

Revenues generated from Mont Belvieu operations increased $0.5 million for the year 2000, compared with 1999, primarily due to increased brine handling fees and higher storage revenue.

Other operating revenues increased $3.3 million during the year ended 2000, compared with 1999, primarily due to $1.8 million of deficiency revenue recognized in the fourth quarter of 2000 related to the beginning of a 20-year contract for petrochemical deliveries at Port Arthur, and a $0.5 million increase in gains on the sale of product inventory attributable to higher market prices in 2000. The additional increases resulted from increased refined products terminaling revenue and increased custody transfer services at Mont Belvieu facilities.

Costs and expenses of the Downstream Segment increased $5.8 million during the year ended 2000, compared with 1999, due to a $2.9 million increase in operating, general and administrative expenses, a $2.3 million increase in operating fuel and power expense and a $0.6 million increase in depreciation and amortization charges. The increase in operating, general and administrative expenses was primarily attributable to $0.9 million of expense recognized in the first quarter of 2000 to write-off project evaluation costs, a $2.3 million increase in general and administrative supplies and services, a $1.5 million increase in legal services, a $1.0 million increase in pipeline operations and maintenance expenses, a $0.7 million increase in labor related expenses and a $0.3 million increase in product measurement losses. The write-off of project evaluation costs resulted from the announcement in March 2000 of the Partnership's abandonment of its plan to construct a pipeline from Beaumont to Little Rock in favor of participation in the Centennial joint venture. These increases in operating, general and administrative expenses were partially offset by a $3.9 million decrease in expenses associated with Year 2000 activities incurred in 1999. The increase in operating fuel and power expense from the prior year resulted primarily from higher fuel prices charged by electric utilities in 2000. Depreciation and amortization expense increased as a result of $0.3 million in depreciation expense related to the completion of the petrochemical pipelines and other capital additions placed in service throughout 2000.

Upstream Segment

Margin of the Upstream Segment is 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. Margin is a more meaningful measure of financial performance than operating revenues and operating expenses due to the significant fluctuations in revenues and expenses caused by variations in the level of marketing activity and prices for products marketed. Margin and volume information for the years ended 2001, 2000 and 1999 is presented below (in thousands, except per barrel and per gallon amounts):

	Years Ended December 31,		
	2001	2000	1999
Margins:			
Crude oil transportation	$ 34,316	$ 23,486	$17,873
Crude oil marketing	21,664	13,320	12,065
Crude oil terminaling	9,769	4,554	—
Lubrication oil sales	4,127	3,503	2,510
Total margin	$ 69,876	$ 44,863	$32,448
Total barrels:			
Crude oil transportation	78,714	46,225	33,267
Crude oil marketing	159,477	107,607	96,252
Crude oil terminaling	121,932	56,473	—
Lubrication oil volume (total gallons):	8,769	7,974	8,891
Margin per barrel:			
Crude oil transportation	$ 0.436	$ 0.508	$ 0.537
Crude oil marketing	$ 0.136	$ 0.124	$ 0.125
Crude oil terminaling	$ 0.080	$ 0.081	—
Lubrication oil margin (per gallon):	$ 0.471	$ 0.439	$ 0.282

2001 Compared to 2000

For the year ended 2001, the Upstream Segment reported earnings before interest of $38.0 million, compared with earnings before interest of $26.4 million for the year ended 2000. The $11.6 million increase in earnings before interest was primarily due to a $25.0 million increase in margin, a $6.4 million increase in other operating revenues, a $6.3 million increase in equity earnings of Seaway, and a $1.5 million increase in other income — net. These increases were partially offset by a $27.9 million increase in costs and expenses (excluding purchases of crude oil and petroleum products). Factors influencing these variances are described below.

Margin increased $25.0 million during the year ended 2001, compared with 2000. Crude oil transportation margin increased $10.8 million primarily due to a full year benefit from the ARCO assets acquired in July 2000 and higher volume on the Red River and South Texas systems, which benefited from increased regional crude oil production and pipeline assets acquired from Valero Energy Corp. (formerly Ultramar Diamond Shamrock) (“UDS”), in March 2001. Crude oil marketing margin increased $8.3 million primarily due to volumes transported by Seaway on behalf of the Upstream Segment. The transportation revenues associated with these volumes resulted in $10.1 million included as a component of crude oil marketing margin when consolidating the Upstream Segment’s equity ownership in Seaway. Lower margins on other crude oil volumes marketed partially offset the increase in crude oil marketing margin. Crude oil terminaling margin increased $5.2 million as a result of pumpover volumes at Midland and Cushing, related to the ARCO assets acquired in July 2000. Margin contributed from lubrication oil sales increased $0.6 million primarily due to increased volumes and increased rates on the margin realized per gallon.

Costs and expenses of the Upstream Segment, excluding expenses associated with purchases of crude oil and petroleum products, increased $27.9 million during the year ended 2001, compared with 2000. The increase was comprised of a $20.5 million increase in operating, general and administrative expenses, a $3.0 million increase in depreciation and amortization expense, a $3.9 million increase in taxes — other than income taxes, and a $0.6 million increase in operating fuel and power expense. The increase in operating, general and administrative expenses was primarily attributable to operating expenses of the acquired assets from ARCO, DEFS and UDS, a $4.4 million expense recorded in 2001 for environmental remediation, increased labor related costs and increased general and administrative supplies and services expense. The increases in depreciation and amortization expense, taxes — other than income taxes, and operating fuel and power expense were primarily attributable to assets acquired.

Equity earnings in Seaway increased $6.3 million for the year ended 2001, compared with 2000, due to the full year contribution to earnings during 2001. Equity earnings in Seaway will be affected in 2002 as a result of the reduction of the sharing percentages of TCTM under the Seaway partnership agreement. Beginning in June 2002, the Partnership participation in Seaway will decrease from 80% of revenue and expense of Seaway to 60%. See Items 1 and 2. Business and Properties, "Upstream Segment — Gathering, Transportation, Marketing and Storage of Crude Oil" for a more detailed discussion.

Other operating revenue of the Upstream Segment increased $6.4 million for the year ended 2001, compared with 2000, attributable to revenue from documentation and other services to support customer trading activity at Midland and Cushing. These revenues were added to the Partnership's business on July 20, 2000, with the acquired ARCO assets.

2000 Compared to 1999

For the year ended 2000, the Upstream Segment reported earnings before interest of $26.4 million, compared with earnings before interest of $7.4 million for the year ended 1999. The $19.0 million increase in earnings before interest was comprised of a $12.4 million increase in margin, a $4.8 million increase in other operating revenues and $12.2 million of equity earnings of Seaway, partially offset by a $10.4 million increase in costs and expenses (excluding purchases of crude oil and petroleum products). Factors influencing these variances are described below.

Margin increased $12.4 million for the year ended 2000, compared with 1999. The increase was comprised of a $5.6 million increase in crude oil transportation; a $4.6 million increase in crude oil terminaling attributable to pumpover fees charged at Midland and Cushing, related to the ARCO assets acquired in July 2000; a $1.3 million increase in crude oil marketing activity and a $1.0 million increase in lubrication oil sales. The increase in crude oil transportation margin was primarily attributable to $3.3 million contributed by the ARCO assets acquired and $2.3 million from increased volume and higher transportation rates on the South Texas and Red River systems, which benefited from higher crude oil market prices. The increase in crude oil marketing margin resulted from an increase in volumes marketed and higher sales prices on volumes in third party pipeline systems. Total lubrication oil volumes decreased 10% from the prior year due primarily to the discontinuation of low margin fuel oil sales, effective April 2000.

Other operating revenue of the Upstream Segment included $4.8 million of revenue related to documentation and other services to support customer trading activity at Midland and Cushing. These revenues were added to the Partnership's business on July 20, 2000, with the acquired ARCO assets.

Costs and expenses of the Upstream Segment, excluding expenses associated with purchases of crude oil and petroleum products, increased $10.4 million for the year ended 2000, compared with 1999, attributable primarily to $6.9 million in costs and expenses from the acquired ARCO assets and a $3.9 million increase in other operating, general and administrative expenses. The costs and expenses associated with the acquired ARCO assets included $4.3 million in operating, general and administrative expenses, $1.3 million in depreciation and amortization charges, $1.1 million in operating fuel and power and $0.2 million in taxes — other than income taxes. The remaining increase in operating, general and administrative expenses of the Upstream Segment resulted primarily from pipeline system maintenance on the South Texas System in the third quarter, increased labor related costs, additional operating costs associated with asset acquisitions in North Texas and increased general and administrative expenses for telecommunications and contract labor charges.

Earnings before interest of the Upstream Segment included $12.2 million of equity earnings in Seaway, which were added to the Partnership's business on July 20, 2000, with the acquired ARCO assets.

Midstream Segment

The following table presents volume and average rate information for the years ended December 31, 2001, 2000 and 1999:

	Years Ended December 31,		
	2001	2000	1999
Gathering — Natural Gas:			
Bcf	45.5	—	—
Transportation — NGLs:			
Thousand barrels	21,538	5,201	4,580
Average rate per barrel	$ 0.972	$1.348	$1.377
Fractionation — NGLs:			
Thousand barrels	4,078	4,078	3,819
Average rate per barrel	$ 1.813	$1.828	$1.926
Sales — Condensate:			
Thousand barrels	16.2	—	—
Average rate per barrel	$ 19.91	—	—

2001 Compared to 2000

For the year ended 2001, the Midstream Segment reported earnings before interest of $15.9 million, compared with earnings before interest of $9.1 million for the year ended 2000. The $6.8 million increase in earnings before interest was due to a $22.8 million increase in operating revenues, partially offset by an $15.8 million increase in costs and expenses and a $0.2 million decrease in other income — net. Factors influencing these variances are described below.

Operating revenues increased $22.8 million during the year ended 2001, compared with the year ended 2000. Operating revenues for the year ended 2001 for Jonah were $9.1 million. Natural gas gathering revenues totaled $8.8 million from volumes delivered of 45.5 billion cubic feet. An additional $0.3 million was generated from the sale of 16,180 barrels of condensate liquid to an Upstream Segment marketing affiliate. Other revenues increased $0.3 million due to sales of gas condensate from the Jonah system, which was acquired on September 30, 2001. NGL transportation revenues increased $13.7 million primarily due to the acquisition of the Panola system on December 31, 2000, and was partially offset by decreased volumes on the Dean pipeline system in South Texas.

Costs and expenses increased $15.8 million during the year ended 2001, compared with the year ended 2000. Costs and expenses for Jonah were $6.0 million and were comprised of $4.5 million of depreciation and amortization expense, $1.4 million of operating, general and administrative expense and $0.1 million of taxes — other than income taxes. Costs and expenses also included $4.1 million due to the acquisition of the Panola system on December 31, 2000, comprised of $1.4 million of operating, general and administrative expense, $2.2 million of depreciation and amortization expense and $0.5 million of taxes — other than income taxes. The increase in costs and expenses also included a $4.3 million reserve for a doubtful receivable balance under a transportation contract with an Enron Corp. subsidiary. The remaining increase was due to increased labor related costs and increased general and administrative supplies and services expense.

2000 Compared to 1999

For the year ended 2000, the Midstream Segment reported earnings before interest of $9.1 million, compared with earnings before interest of $8.5 million for the year ended 1999. The $0.6 million increase in earnings before interest was due to a $1.0 million increase in operating revenues, partially offset by a $0.4 million increase in costs and expenses. Factors influencing these variances are described below.

Operating revenues increased $1.0 million during the year ended 2000, compared with the year ended 1999. The increase is due to increased NGL transportation volumes and higher prices on loss allowance barrels received on the Dean Pipeline.

Costs and expenses increased $0.4 million during the year ended 2000, compared with the year ended 1999. The increase is due to a $0.4 million increase in operating, general and administrative expenses, resulting from pipeline maintenance and increased labor related costs.

Interest Expense and Capitalized Interest

2001 Compared to 2000

Interest expense increased $17.1 million during the year ended 2001, compared with the year ended 2000, primarily due to higher outstanding debt balances used to finance the acquisition of assets acquired in the Midstream Segment and the Upstream Segment. These increases were partially offset by lower interest rates on borrowings under the variable-rate credit facilities and the favorable impact of the fixed-to-floating interest rate swap on the TE Products Senior Notes, effective October 4, 2001.

Capitalized interest decreased $0.6 million during the year ended 2001, compared with the year ended 2000, due to the completion of the petrochemical pipelines from Mont Belvieu to Port Arthur, Texas, during the fourth quarter of 2000. This decrease was partially offset by increased balances on construction work-in-progress in the Upstream and Midstream Segments.

2000 Compared to 1999

Interest expense increased $17.4 million during the year ended 2000, compared with the year ended 1999, primarily due to higher outstanding debt balances under a term loan to finance construction of the petrochemical pipelines between Mont Belvieu and Port Arthur. Additionally, amortization of debt issue costs increased $0.8 million during the year ended 2000. Interest expense also increased due to interest expense on the term loan and revolving credit facilities used to finance the acquisition of the ARCO assets.

Capitalized interest increased $2.4 million during the year ended 2000, compared with the year ended 1999, due to the construction of the petrochemical pipelines from Mont Belvieu to Port Arthur.

Financial Condition and Liquidity

Net cash from operations for the year ended 2001 totaled $169.2 million, and was comprised of $155.0 million of income before charges for depreciation and amortization, and $14.2 million of cash provided by working capital changes. Net cash from operations for the year ended 2000 totaled $108.0 million, and was comprised of $112.5 million of income before charges for depreciation and amortization, partially offset by $4.5 million of cash used for working capital changes. Net cash from operations for the year ended 1999 totaled $103.1 million, and was comprised of $104.8 million of income before charges for depreciation and amortization, partially offset by $1.7 million of cash used for working capital changes. Net cash from operations for the years ended 2001, 2000, and 1999 included interest payments of $61.5 million, $36.8 million, and $28.6 million, respectively.

Cash flows used in investing activities totaled $557.9 million during the year ended 2001, and was comprised of $359.8 million for the purchase of Jonah on September 30, 2001, $107.6 million of capital expenditures, $65.0 million of cash contributions for the Partnership's interest in the Centennial joint venture, $20.0 million for the purchase of crude oil assets from UDS on March 1, 2001, and $11.0 million paid in October 2001, for the final purchase price settlement related to the previously acquired ARCO assets. These uses of cash were partially offset by $4.2 million received on matured cash investments and $1.3 million of cash received from the sale of vehicles. Cash flows used in investing activities totaled $494.1 million during the year ended 2000, and was comprised of $322.6 million for the purchase of the ARCO assets, $99.5 million for NGL and crude oil systems purchased in East Texas and North Texas, $68.5 million of capital expenditures, $5.0 million of cash contributions for the Partnership's interest in the Centennial joint venture, and $2.0 million of cash investments. These uses of cash were partially offset by $3.5 million received from matured cash investments. Cash flows used in investing activities totaled $76.6 million for the year ended 1999, and included $77.4 million of capital expenditures and $2.3 million for the purchase of a 125-mile crude oil system in Southeast Texas, offset by net proceeds from cash investments of $3.0 million. Capital expenditures during the years ended 2000 and 1999 included $29.9 million and $43.8 million, respectively, of spending for construction of the petrochemical pipelines between the Partnership's terminal in Mont Belvieu and Port Arthur.

In August 2000, TE Products entered into agreements with CMS Energy Corporation and Marathon Ashland Petroleum LLC to form Centennial. TE Products has contributed approximately $65.0 million and $5.0 million during the years ended 2001 and 2000, respectively, for its one-third interest in Centennial. The Partnership expects to contribute an additional $4.9 million to Centennial in 2002. Centennial commenced operations in the first quarter of 2002.

Centennial has entered into credit facilities totaling $150 million. The proceeds were used to fund construction and conversion costs of its pipeline system. As of December 31, 2001, Centennial had borrowed $128 million under its credit facility. TE Products has guaranteed one-third of the debt of Centennial up to a maximum amount of $50 million.

Credit Facilities and Interest Rate Swap Agreements

In July 2000, the Partnership entered into a $75 million term loan and a $475 million revolving credit facility ("Three Year Facility") and borrowed $75 million and $340 million, respectively, to finance the acquisition of the ARCO assets and to refinance existing bank credit facilities. The term loan was repaid from proceeds received from the issuance of additional Limited Partner Units on October 25, 2000. In April 2001, the Three Year Facility was amended to provide for revolving borrowings of up to $500 million including the issuance of letters of credit of up to $20 million. The term of the revised Three Year Facility was extended to April 6, 2004. The interest rate is based on the Partnership's option of 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 contains restrictive financial covenants that require the Partnership to maintain a minimum level of partners' capital as well as maximum debt-to-EBITDA (earnings before interest expense, income tax expense and depreciation and amortization expense) and minimum fixed charge coverage ratios.

In April 2001, the Partnership entered into a 364-day, $200 million revolving credit agreement ("Short-term Revolver"). The interest rate is based on the Partnership's option of 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 contains restrictive financial covenants that require the Partnership to maintain a minimum level of partners' capital as well as maximum debt-to-EBITDA and minimum fixed charge coverage ratios. The Partnership has requested an extension of the Short-term Revolver for an additional period of 364 days, commencing on the current termination date in April 2002. Extension of the Short-term Revolver is expected prior to the termination date.

On September 28, 2001, the Three Year Facility and the Short-term Revolver were amended to extend to December 31, 2001, the time period for the maximum debt-to-EBITDA ratio covenant to allow for the additional debt incurred for the acquisition of Jonah. On November 13, 2001, the Three Year Facility and the Short-term Revolver were further amended to require prepayment of outstanding borrowings only upon the receipt of net cash proceeds from asset dispositions or from insurance proceeds in accordance with the terms of the respective agreements. At such time, certain lenders under the agreements elected to withdraw from the facilities, and the available borrowing capacities were reduced to $411 million and $164 million, respectively. At December 31, 2001 and 2000, $340.7 million and $446 million was outstanding under the Three Year Facility at a weighted average interest rate of 2.9% and 8.23%, respectively, and no letters of credit were outstanding. At December 31, 2001, $160 million, included in current liabilities, was outstanding under the Short-term Revolver at a weighted average interest rate of 2.9%. As of December 31, 2001, the Partnership was in compliance with the covenants contained in the agreements. On January 16, 2002, an additional $25 million was drawn down on the Three Year Facility. On February 20, 2002, the Partnership repaid $115.7 million of the then outstanding balance of the Three Year Facility and all of the then outstanding balance of the Short-term Revolver with proceeds from the issuance by the Partnership of the 7.625% Senior Notes, discussed below.

On September 28, 2001, the Partnership entered into a $400 million credit facility with SunTrust Bank ("Bridge Facility"). The Partnership borrowed $360 million under the Bridge Facility for the acquisition of the Jonah assets. During the fourth quarter of 2001, $160 million of the outstanding principal was repaid from the proceeds received from the issuance of the Limited Partner Units in November 2001. The interest rate is based on the Partnership's option of either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. At December 31, 2001, $200 million was outstanding under the Bridge Facility at an interest rate of 3.2%. As of December 31, 2001, the Partnership was in compliance with the covenants contained in this credit agreement. On February 5, 2002, an additional $15 million was drawn down on the Bridge Facility. On February 20, 2002, the Partnership repaid the then outstanding balance of the Bridge Facility of $215 million, with proceeds from the issuance by the Partnership of its 7.625% Senior Notes, discussed below, and canceled the remaining commitment.

On February 20, 2002, the Partnership received $494.6 million in net proceeds from the issuance of $500 million principal amount of its 7.625% Senior Notes due 2012. The proceeds from the offering were used to reduce the outstanding balances of the credit facilities, described above, including those issued in connection with the acquisition of Jonah. The Senior Notes may be redeemed at any time at the option of the Partnership 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.

In 2001 and 2000, the Partnership entered into interest rate hedge agreements with notional amounts and expirations related to particular indebtedness, as more fully described in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk."

On March 1, 2002, the Partnership completed the acquisition of the Chaparral and Quanah pipelines from Diamond-Koch II, L.P. and Diamond-Koch III, L.P. for approximately $132 million. This purchase was funded by a drawdown on the Three Year Facility. The Chaparral system is an 800-mile pipeline that extends from West Texas and New Mexico to Mont Belvieu. The pipeline delivers NGLs to fractionators and existing Partnership storage in Mont Belvieu. The approximately 170-mile Quanah Pipeline is an NGL gathering system located in West Texas. The Quanah Pipeline begins in Sutton County, Texas and connects to the Chaparral Pipeline near Midland. The pipelines are connected to 27 gas plants in West Texas and have approximately 28,000 horsepower of pumping capacity at 14 stations. These systems will be managed and operated by DEFS under a contract arrangement.

The following table summarizes the credit facilities of the Partnership as of December 31, 2001, and March 7, 2002 (in millions):

	As of December 31, 2001			As of March 7, 2002		
Description:	**Outstanding Principal**	**Unused Borrowing Capacity**	**Maturity Date**	**Outstanding Principal**	**Unused Borrowing Capacity**	**Maturity Date**
Short-term Revolver	$160.0	$ 4.0	April 2002	$ —	$164.0	April 2002
Three Year Facility	340.7	70.3	April 2004	382.0	29.0	April 2004
Bridge Facility	200.0	200.0	June 2002	—	—	—(1)
6.45% Senior Notes	180.0	—	January 2008	180.0	—	January 2008
7.51% Senior Notes	210.0	—	January 2028	210.0	—	January 2028
7.625% Senior Notes	—	—	—	500.0	—	February 2012

(1) The remaining commitment under the Bridge Facility was canceled in February 2002.

Distributions and Issuance of Additional Limited Partner Units

The Partnership paid cash distributions of $104.4 million ($2.15 per Unit), $82.2 million ($2.00 per Unit) and $69.3 million ($1.85 per Unit), for each of the years ended 2001, 2000 and 1999, respectively. Additionally, on January 18, 2002, the Partnership declared a cash distribution of $0.575 per Limited Partner Unit and Class B Unit for the quarter ended December 31, 2001. The distribution of $33.5 million was paid on February 8, 2002, to unitholders of record on January 31, 2002.

On November 20, 2001, the Partnership completed the issuance by public offering of 5.5 million Limited Partner Units at $34.25 per Unit. The net proceeds from the offering totaled approximately $180.1 million and were used to repay $160.0 million under the Bridge Facility that was used to fund the Jonah acquisition. The remaining proceeds were used to finance contributions to Centennial and for other capital expenditures.

On February 6, 2001, the Partnership completed the issuance by public offering of 2.0 million Limited Partner Units at $25.50 per Unit. The net proceeds from the offering totaled approximately $48.5 million and was used to reduce borrowings under the Three Year Facility. On March 6, 2001, 250,000 Units were issued in connection with the over-allotment provision of the offering on February 6, 2001. Proceeds from the Units issued from the over-allotment totaled $6.1 million and were used for general Partnership purposes.

On October 25, 2000, the Partnership completed the issuance by public offering of 3.7 million Limited Partner Units at $25.06 per Unit. The net proceeds from the offering totaled approximately $88.5 million and was used to repay the $75 million principal amount of the term loan and $11 million of the outstanding principal amount of the revolving portion of the Three Year Facility.

Future Capital Needs and Commitments

Capital expenditures for the year ended December 31, 2001, and estimated capital expenditures, excluding acquisitions, for 2002 are described in Items 1 and 2, Business and Properties under the caption “Capital Expenditures.” The Partnership continually reviews and evaluates potential acquisitions, capital improvements and expansions and, to a more limited extent, joint venture opportunities that would be complementary to its present business segments. Should the Partnership elect to pursue any of these transactions, the Partnership will likely need additional capital to fund the purchase price and other capital improvements. These expenditures can vary greatly depending on the magnitude of these transactions by the Partnership. In March 2002, the Partnership completed the acquisition of the Chaparral and Quanah pipelines for approximately $132 million. The purchase was funded by a drawdown on the Three Year Facility.

The Partnerships’ debt repayment obligations consist of payments for principal and interest on (i) outstanding principal amounts under the Three Year Facility due in April 2004 ($382 million at March 7, 2002), (ii) the TE Products Senior Notes, $180 million principal amount due January 15, 2008, and $210 million principal amount due January 15, 2028, and (iii) the Partnership’s $500 million 7.625% Senior Notes due February 15, 2012. Repayment of the long-term, senior unsecured obligations and bank debt is expected to be repaid through issuance of additional long-term senior unsecured debt at the time the 2008, 2012 and 2028 debt matures, issuance of additional equity, proceeds from dispositions of assets, or any combination of the above items.

TE Products is also contingently liable as guarantor for the lesser of one-third or $50 million principal amount (plus interest) of the joint venture borrowings of Centennial. The Partnership expects to contribute an additional $4.9 million to Centennial in 2002. The Partnership does not rely on off-balance sheet borrowings to fund its acquisitions. Other than the limited guarantee of Centennial debt and leases covering assets utilized in several areas of its operations, the Partnership has no off-balance sheet commitments for indebtedness.

The following table summarizes the material contractual obligations of the Partnership as of December 31, 2001, after giving pro forma effect to the issuance and application of net proceeds of the Partnership’s 7.625% Senior Notes due 2012 in February 2002 and additional borrowings in March 2002 to fund the purchase of the Chaparral and Quanah pipelines (in millions).

	Amount of Commitment Expiration Per Period				
	Total	Less than 1 Year	2-3 Years	4-5 Years	After 5 Years
Short-term Revolver (1)	$ 160.0	$160.0	$ —	$ —	$ —
Three Year Facility (2)	340.7	—	340.7	—	—
Bridge Facility	200.0	200.0	—	—	—
6.45% Senior Notes due 2008 (3)	180.0	—	—	—	180.0
7.51% Senior Notes due 2028 (3)	210.0	—	—	—	210.0
7.625% Senior Notes due 2012 (4)	500.0	—	—	—	500.0
Centennial cash contributions	4.9	4.9	—	—	—
Operating leases	36.0	8.8	14.8	11.0	1.4
Total	$1,631.6	$373.7	$355.5	$11.0	$891.4

(1) Approximately $160 million was paid down in February 2002 from net proceeds from the offering of the Partnership's 7.625% Senior Notes due 2012.

(2) Approximately $115.7 million was paid down in February 2002 from net proceeds from the offering of the Partnership's 7.625% Senior Notes due 2012. Approximately $132 million was subsequently drawn down in March 2002 to fund the purchase of the Chaparral and Quanah pipelines.

(3) Obligations of TE Products.

(4) Issued by the Partnership in February 2002.

Sources of Future Capital

Historically, the Partnership has funded its capital commitments from operating cash flow and borrowings under bank credit facilities or bridge loans. These loans were repaid in part by the issuance of long term debt in capital markets and the public offering of Limited Partner Units. The Company expects future capital needs would be similarly funded to the extent not otherwise available from excess cash flow from operations after payment of distributions on Limited Partner Units.

As of March 7, 2002, and after giving effect to borrowings required to fund the acquisition of the Chaparral and Quanah pipelines, the Partnership has approximately $193.0 million in combined available borrowing capacity under the Three Year Facility and the Short-term Revolver.

The Company expects that the Partnership's cash flow from operating activities will be adequate to fund cash distributions and capital additions necessary to maintain existing operations. However, expansionary capital projects and acquisitions may require funding through proceeds from the sale of additional debt or equity capital markets offerings.

On February 11, 2002, Moody's Investors Service assigned the Partnership a senior unsecured debt rating, including the rating on its 7.625% Senior Notes, of Baa2 and confirmed the Baa2 senior unsecured rating of the subsidiary, TE Products. These ratings were given with negative outlooks due primarily to Moody's concerns about current debt levels resulting from financing of the Partnership's recent acquisitions. Moody's indicated they may lower the Partnership's ratings if the Partnership is not successful in reducing its debt to target levels where the Partnership's debt-to-EBITDA ratio would be below 4 to 1. The Company is evaluating alternatives to lowering its debt-to-EBITDA ratio. Reductions in the Partnership's credit ratings could increase the debt financing costs or possibly reduce the availability of financing. 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 decides that the circumstances warrant such a change.

Other Considerations

Credit Risks

Risks of nonpayment and nonperformance by customers are a major consideration in the Partnership's businesses. The credit procedures and policies of the Partnership may not fully eliminate customer credit risk. The bankruptcy of Enron Corp. and certain of its subsidiaries in December 2001 has made collection by the Partnership of a receivable for transportation fees of approximately $4.3 million, or approximately $0.09 per limited partner and Class B Units at December 31, 2001, doubtful.

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 the Partnership's operations to increased risks. Any terrorist attack on the Partnership's facilities, customers' facilities and, in some cases, those of other pipelines, could have a material adverse effect on the Partnership's business. The Partnership has increased security initiatives and is working with various governmental agencies to minimize risks associated with additional terrorist attacks.

Environmental

The operations of the Partnership are subject to federal, state and local laws and regulations relating to protection of the environment. Although the Partnership believes its operations are in material compliance with applicable environmental regulations, risks of significant costs and liabilities are inherent in pipeline operations, and there can be no assurance 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 the operations of the pipeline system, could result in substantial costs and liabilities to the Partnership. The Partnership does not anticipate that changes in environmental laws and regulations will have a material adverse effect on its financial position, results of operations or cash flows in the near term.

In 1994, the Partnership and the IDEM entered into an Agreed Order that resulted in the implementation of a remediation program for groundwater contamination attributable to the Partnership's operations at the Seymour, Indiana, terminal. A Feasibility Study, which includes the Partnership's proposed remediation program, was approved by IDEM in 1999. IDEM is expected to issue a Record of Decision formally approving the remediation program. After the Record of Decision is issued, the Partnership will enter into a subsequent Agreed Order for the continued operation and maintenance of the remediation program. The Partnership has an accrued liability of $0.6 million on December 31, 2001, for future remediation costs at the Seymour terminal. In the opinion of the Company, the completion of the remediation program will not have a future material adverse effect on the Partnership's financial condition, results of operations or cash flows.

In 1994, the Partnership was issued a compliance order from the LDEQ relative to environmental contamination at the Partnership's Arcadia, Louisiana, facility. This contamination may be attributable to the operations of the Partnership, as well as adjacent petroleum terminals operated by other companies. In 1999, the Partnership's Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this containment phase. In the opinion of the Company, the completion of the remediation program that is proposed by the Partnership will not have a future material adverse effect on the Partnership's financial position, results of operations or cash flows.

During 2001, the Partnership accrued $8.6 million to complete environmental remediation activities at certain of the sites owned by TCTM and its subsidiaries. In establishing this accrual, the Partnership expensed $4.4 million for these environmental remediation costs and recorded a receivable of $4.2 million for the remainder. The receivable is based on a contractual indemnity obligation for specified environmental liabilities owed by DEFS to the Partnership in connection with the Partnership's acquisition of the Upstream Segment from DEFS in November 1998. Under this indemnity obligation, the Partnership is responsible for the first $3.0 million in specified environmental liabilities, with DEFS becoming responsible for those environmental liabilities in excess of $3.0 million, up to a maximum amount of $25.0 million. At December 31, 2001, an accrual of $6.4 million remains outstanding related to TCTM environmental remediation activities. The majority of the indemnified costs relate to remediation activities at the Velma crude oil site in Stephens County, Oklahoma, attributable to operations prior to the Partnership's acquisition of the Upstream Segment. Remediation activities at the Velma crude oil site are being conducted according to a work plan approved by the Oklahoma Corporation Commission. In the opinion of the Company, the completion of remediation programs associated with this release will not have a future material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Market-Based Rates

On May 11, 1999, TE Products filed an application with the FERC requesting permission to charge Market-Based Rates for substantially all refined products transportation tariffs. On July 31, 2000, the FERC issued an order granting TE Products Market-Based Rates in certain markets and set for hearing TE Products' application for Market-Based Rates in certain destination markets and origin markets. After the matter was set for hearing, TE Products and the protesting shippers entered into a settlement agreement resolving their respective differences. On April 25, 2001, the FERC issued an order approving the offer of settlement. As a result of the settlement, TE Products recognized approximately $1.7 million of previously deferred transportation revenue in the second quarter of 2001. As a part of the settlement, TE Products withdrew the application for Market-Based Rates to the Little Rock, Arkansas, Arcadia and Shreveport-Arcadia, Louisiana, destination markets, which are currently subject to the PPI Index. As a result, the Partnership made refunds of approximately $1.0 million in the third quarter of 2001 for those destination markets.

New Accounting Pronouncements

In July 2001, the FASB issued SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS 141 requires that the purchase method of accounting be used for all business combinations and specifies that certain acquired intangible assets be reported apart from goodwill. SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually. SFAS 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives. The Partnership adopted SFAS 141 during 2001, and SFAS 142 effective January 1, 2002. At the date of this report, the Partnership is evaluating the impact of adopting SFAS 142, including whether any transitional impairment losses will be required to be recognized as the cumulative effect of a change in accounting principle. At December 31, 2001, the Partnership had $14.7 million of unamortized goodwill. Amortization expense related to goodwill was $0.9 million and $0.1 million for the years ended December 31, 2001 and 2000, respectively. The goodwill associated with the acquisition of Jonah, which was completed on September 30, 2001, is not being amortized due to the adoption of certain provisions of SFAS 142.

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development and/or normal use of the assets. The Partnership also records a corresponding asset, which is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Partnership is required to adopt SFAS 143 effective January 1, 2003.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS 144 supercedes SFAS No. 121, *Accounting for Long-Lived Assets and For Long-Lived Assets to be Disposed Of*, but retains its fundamental provisions for reorganizing and measuring impairment losses on long-lived assets held for use and long-lived assets to be disposed of by sale. The Partnership was required to adopt

SFAS 144 effective January 1, 2002. The adoption of SFAS 144 did not have a material effect on the financial position, results of operations or cash flows of the Partnership.

Disclosures About Effects of Transactions with Related Parties

The Partnership has no employees and is managed by the Company, a wholly-owned subsidiary of DEFS. Duke Energy holds an approximate 70% interest in DEFS and Phillips holds the remaining 30%. See Item 10, Directors and Executive Officers of the Registrant and Item 13, Certain Relationships and Related Transactions for discussion regarding transactions between the Partnership and DEFS, Duke Energy and Phillips.

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 the Partnership expects or anticipates 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 the Partnership's 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 the Partnership in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. However, whether actual results and developments will conform with the Partnership's 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 the Partnership, competitive actions by other pipeline companies, changes in laws or regulations, and other factors, many of which are beyond the control of the Partnership. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements and there can be no assurance that actual results or developments anticipated by the Partnership will be realized or, even if substantially realized, that they will have the expected consequences to or effect on the Partnership or its business or operations.

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements of the Partnership, together with the independent auditors' report thereon of KPMG LLP, begin on page F-1 of this Report.

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

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

(1) Financial Statements: See Index to 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
23.1*	Consent of KPMG LLP.

* Filed herewith.

(b) Reports on Form 8-K filed during the quarter ended December 31, 2001:

Reports on Form 8-K were filed on October 15, 2001, November 9, 2001, November 13, 2001, November 19, 2001, and November 30, 2001.

SIGNATURES

TEPPCO Partners, L.P., pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, has duly caused this amendment to 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: June 3, 2002

Table of Contents

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

Signature	Title	Date
BARRY R. PEARL Barry R. Pearl	President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
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)	June 3, 2002
JIM W. MOGG* Jim W. Mogg	Chairman of the Board of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
MARK A. BORER * Mark A. Borer	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
MILTON CARROLL* Milton Carroll	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
CARL D. CLAY* Carl D. Clay	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
DERRILL CODY* Derrill Cody	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
JOHN P. DESBARRES* John P. DesBarres	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
FRED J. FOWLER* Fred J. Fowler	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002
WILLIAM W. SLAUGHTER* William W. Slaughter	Director of Texas Eastern Products Pipeline Company, LLC	June 3, 2002

* 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 FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

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, 2001 and 2000, 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, 2001. 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 auditing standards generally accepted in the United States of America. 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, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 2 to the consolidated financial statements, as of January 1, 2001, the Partnership changed its method of accounting for derivative instruments and hedging activities and, effective July 1, 2001, adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations,* and certain provisions of SFAS No. 142, *Goodwill and Other Intangible Assets.*

KPMG LLP

Houston, Texas
January 17, 2002, except as
to Note 15, which is as of
May 30, 2002

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2001	December 31, 2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 25,479	$ 27,096
Accounts receivable, trade	221,541	303,394
Accounts receivable, related party	4,310	—
Inventories	17,243	24,784
Other	14,907	8,123
Total current assets	283,480	363,397
Property, plant and equipment, at cost (Net of accumulated depreciation and amortization of $290,248 and $251,165)	1,180,461	949,705
Equity investments	292,224	241,648
Intangible assets	253,413	34,174
Goodwill	14,743	4,214
Other assets	41,027	29,672
Total assets	$2,065,348	$1,622,810
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Notes payable	$ 360,000	$ —
Accounts payable and accrued liabilities	228,075	293,720
Accounts payable, general partner	22,680	6,637
Accrued interest	15,649	18,633
Other accrued taxes	8,888	10,501
Other	33,550	28,780
Total current liabilities	668,842	358,271
Senior Notes	389,814	389,784
Other long-term debt	340,658	446,000
Other liabilities and deferred credits	17,223	3,991
Minority interest	—	4,296
Redeemable Class B Units held by related party	105,630	105,411
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive loss	(20,324)	—
General partner's interest	13,190	1,824
Limited partners' interests	550,315	313,233
Total partners' capital	543,181	315,057
Total liabilities and partners' capital	$2,065,348	$1,622,810

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, 2001	2000	1999
Operating revenues:			
Sales of crude oil and petroleum products	$3,219,816	$2,821,943	$1,692,767
Transportation — refined products	139,315	119,331	123,004
Transportation — LPGs	77,823	73,896	67,701
Transportation — crude oil and NGLs	44,925	24,533	11,846
Gathering — natural gas	8,824	—	—
Mont Belvieu operations	14,116	13,334	12,849
Other	51,594	34,904	26,716
Total operating revenues	3,556,413	3,087,941	1,934,883
Costs and expenses:			
Purchases of crude oil and petroleum products	3,173,607	2,794,604	1,666,042
Operating, general and administrative	135,253	104,918	94,340
Operating fuel and power	36,575	34,655	31,265
Depreciation and amortization	45,899	35,163	32,656
Taxes — other than income taxes	14,090	10,576	10,490
Total costs and expenses	3,405,424	2,979,916	1,834,793
Operating income	150,989	108,025	100,090
Interest expense	(66,057)	(48,982)	(31,563)
Interest capitalized	4,000	4,559	2,133
Equity earnings	17,398	12,214	—
Other income — net	3,601	2,349	2,196
Income before minority interest	109,931	78,165	72,856
Minority interest	(800)	(789)	(736)
Net income	$ 109,131	$ 77,376	$ 72,120
Net income allocated to Limited Partner Unitholders	76,986	56,091	55,349
Net income allocated to Class B Unitholder	8,642	7,385	7,475
Net income allocated to General Partner	23,503	13,900	9,296
Total net income allocated	$ 109,131	$ 77,376	$ 72,120
Basic and diluted net income per Limited Partner and Class B Unit	$ 2.18	$ 1.89	$ 1.91
Weighted average Limited Partner and Class B Units outstanding	39,258	33,594	32,917

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2001	**2000**	**1999**
Cash flows from operating activities:			
Net income	$ 109,131	$ 77,376	$ 72,120
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	45,899	35,163	32,656
Equity in earnings, net of distributions	14,377	(10,084)	393
Non-cash portion of interest expense	4,053	2,218	337
Decrease (increase) in accounts receivable	81,190	(90,006)	(92,225)
Decrease (increase) in inventories	7,541	(7,567)	1,037
Decrease (increase) in other current assets	(8,082)	1,165	(2,500)
Increase (decrease) in accounts payable and accrued expenses	(71,757)	106,662	93,317
Other	(13,204)	(6,882)	(2,065)
Net cash provided by operating activities	169,148	108,045	103,070
Cash flows from investing activities:			
Proceeds from cash investments	4,236	3,475	6,275
Purchases of cash investments	—	(2,000)	(3,235)
Purchase of ARCO assets	(11,000)	(322,640)	—
Purchase of Jonah Gas Gathering Company	(359,834)	—	—
Purchase of crude oil assets and NGL system	(20,000)	(99,508)	(2,250)
Proceeds from the sale of assets	1,300	—	—
Investment in Centennial Pipeline, LLC	(64,953)	(5,040)	—
Capital expenditures	(107,614)	(68,481)	(77,431)
Net cash used in investing activities	(557,865)	(494,194)	(76,641)
Cash flows from financing activities:			
Proceeds from term and revolving credit facilities	546,148	552,000	33,000
Repayments on term and revolving credit facilities	(291,490)	(172,000)	(5,000)
Debt issuance cost	(2,601)	(7,074)	—
Issuance of Limited Partner Units, net	234,660	88,158	—
General partner's contributions	4,795	1,799	—
Distributions	(104,412)	(82,231)	(69,259)
Net cash provided by (used in) financing activities	387,100	380,652	(41,259)
Net decrease in cash and cash equivalents	(1,617)	(5,497)	(14,830)
Cash and cash equivalents at beginning of period	27,096	32,593	47,423
Cash and cash equivalents at end of period	$ 25,479	$ 27,096	$ 32,593
Supplemental disclosure of cash flows:			
Interest paid during the year (net of capitalized interest)	$ 61,458	$ 36,793	$ 28,625

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(in thousands)

	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Loss	Total
Partners' capital (deficit) at December 31, 1998	$ (380)	$227,566	$ —	$227,186
1999 net income allocation	9,296	55,349	—	64,645
1999 cash distributions	(8,259)	(53,650)	—	(61,909)
Option exercises, net of Unit repurchases	—	(155)	—	(155)
Partners' capital at December 31, 1999	657	229,110	—	229,767
Capital contributions	890	—	—	890
Issuance of Limited Partner Units, net	—	88,158	—	88,158
2000 net income allocation	13,900	56,091	—	69,991
2000 cash distributions	(13,623)	(59,943)	—	(73,566)
Option exercises, net of Unit repurchases	—	(183)	—	(183)
Partners' capital at December 31, 2000	1,824	313,233	—	315,057
Capital contributions	4,795	—	—	4,795
Issuance of Limited Partner Units, net	—	234,660	—	234,660
Minority interest restructured	4,598	—	—	4,598
Cumulative effect of accounting change	—	—	(10,103)	(10,103)
Net loss on cash flow hedges	—	—	(10,221)	(10,221)
2001 net income allocation	23,503	76,986	—	100,489
2001 cash distributions	(21,530)	(73,961)	—	(95,491)
Option exercises, net of Unit repurchases	—	(603)	—	(603)
Partners' capital at December 31, 2001	$ 13,190	$550,315	$(20,324)	$543,181

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 and was formed in March 1990. The Partnership operates 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 the general partner of the Partnership. The General Partner is a wholly-owned subsidiary of Duke Energy Field Services ("DEFS"), a joint venture between Duke Energy Corporation ("Duke Energy") and Phillips Petroleum Company ("Phillips"). Duke Energy holds an approximate 70% interest in DEFS and Phillips holds the remaining 30%. The Company, as general partner, performs all management and operating functions required for the Partnership and the Operating Partnerships, except for the management and operations of certain of the TEPPCO Midstream assets, which is performed by DEFS under an agreement with the Partnership. The General Partner is reimbursed by the Partnership for all reasonable direct and indirect expenses incurred in managing the Partnership.

On July 26, 2001, the Company restructured its general partner ownership of the Operating Partnerships to cause them to be indirectly wholly-owned by the Partnership. TEPPCO GP, Inc. ("TEPPCO GP"), a subsidiary of the Partnership, succeeded the Company as general partner of the Operating Partnerships. All remaining partner interests in the Operating Partnerships not already owned by the Partnership were transferred to the Partnership. In exchange for this contribution, the Company's interest as general partner of the Partnership 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 the Partnership and the Operating Partnerships. As a result, the Partnership holds 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 guarantees of Partnership debt are issued by the Operating Partnerships.

At formation in 1990, the Partnership completed an initial public offering of 26,500,000 Units representing Limited Partner Interests ("Limited Partner Units") at $10 per Unit. In connection with the formation of the Partnership, 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 and are treated as Limited Partner Units for purposes of this Report. The Partnership has registered the resale of such Limited Partner Units with the Securities and Exchange Commission. As of December 31, 2001, no such Limited Partner Units had been sold by Duke Energy.

At December 31, 2001 and 2000, the Partnership had outstanding 40,450,000 and 32,700,000 Limited Partner Units and 3,916,547 and 3,916,547 Class B Limited Partner Units ("Class B Units"), respectively. All of the Class B Units were issued to Duke Energy in connection with an acquisition of assets initially acquired in the Upstream Segment in 1998. The Class B Units share in income and distributions on the same basis as the Limited Partner Units, but they are not listed on the New York Stock Exchange. The Class B Units may be converted into Limited Partner Units upon approval by the unitholders. The Company has the option to seek approval for the conversion of the Class B Units into Limited Partner Units; however, if the conversion is denied, Duke Energy, as holder of the Class B Units, will have the right to sell them to the Partnership at 95.5% of the then current market price of the Limited Partner Units. As a result of this option, the Class B Units were not included in partners' capital at December 31, 2001 and 2000. Collectively, the Limited Partner Units and Class B Units are referred to as "Units."

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The financial statements include the accounts of the Partnership on a consolidated basis. The Company's 1% general partner interest in the Operating Partnerships, prior to July 26, 2001, is accounted for as a minority interest. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior years have been reclassified to conform to current presentation.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Environmental Expenditures

The Partnership accrues 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 fines, damages and other costs, when estimable. The balance of accrued undiscounted environmental liabilities are monitored on a regular basis by management. Liabilities for environmental costs at a specific site are initially recorded when the Partnership's liability for such costs, including direct internal and legal 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 the Partnership's 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.

Business Segments

The Partnership reports and operates 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"). The Partnership's reportable segments offer different products and services and are managed separately because each requires different business strategies. The Upstream Segment of the Partnership's business was initially acquired in November 1998. Portions of the Midstream Segment of the Partnership's business were acquired in March 1998, November 1998, December 2000 and on September 30, 2001. Certain of the assets of the Midstream Segment are managed and operated by DEFS under an agreement with the Partnership.

Effective January 1, 2002, the Partnership realigned its three business segments in order to separate and better measure the performance of its natural gas and NGL operations and its crude oil operations. The fractionation of NGLs, which was previously reflected as part of the Downstream Segment, was shifted to the Midstream

Segment. The operation of NGL pipelines, which was previously reflected as part of the Upstream Segment, was also shifted to the Midstream Segment. The year-to-year comparisons have been adjusted to conform to the current presentation.

The Partnership's interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC"). Refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas are referred to herein, collectively, as "petroleum products" or "products."

Revenue Recognition

Revenues of the Downstream Segment are derived from transportation and storage of refined products and LPGs, storage and short-haul transportation of LPGs at the Mont Belvieu complex, 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.

Revenues of the Upstream Segment are derived from gathering, transportation, marketing and storage of crude oil; and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas and the Rocky Mountain region. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas (effective July 20, 2000). 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 the Partnership's crude oil marketing company, TEPPCO Crude Oil, L.P., which typically occurs upon receipt of the product by the Partnership. Revenues related to trade documentation and pumpover services are recognized as completed.

Except for crude oil purchased from time to time as inventory, the Partnership's policy is to purchase only crude oil for which it has a market to sell and to structure sales contracts so that crude oil price fluctuations do not materially affect the margin received. As the Partnership purchases crude oil, it establishes a margin by selling crude oil for physical delivery to third party users or by entering into a future delivery obligation either physically or a futures contract on the New York Mercantile Exchange ("NYMEX"). Through these transactions, the Partnership seeks 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.

Revenues of the Midstream Segment are derived from gathering of natural gas in the Green River Basin in southwestern Wyoming, fractionation of NGLs in Colorado 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 marketing affiliate. Fractionation revenues are recognized ratably over the contract year as products are delivered to DEFS. The Partnership does not take title to the natural gas gathered, NGLs transported or NGLs fractionated, therefore, the results of the Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Use of Derivatives

Effective January 1, 2001, the Partnership adopted Statement of Financial Accounting Standards ("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. Special accounting for derivatives qualifying as fair value hedges allows a derivative's gains and losses to offset related results on the hedged item in the statement of income. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. 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. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings.

Adoption of SFAS 133 at January 1, 2001, resulted in the recognition of approximately $10.1 million of derivative liabilities, $4.1 million of which were current liabilities and $6.0 million of which were noncurrent liabilities, and $10.1 million of hedging losses included in accumulated other comprehensive income, a component of Partners' capital, as the cumulative effect of the change in accounting. The hedging losses included in accumulated other comprehensive loss are being transferred to earnings as the forecasted transactions actually occur. Amounts were determined as of January 1, 2001, based on the market quote of the Partnership's interest swap agreement in place at the time of adoption.

The Partnership has utilized and expects to continue to utilize derivative financial instruments with respect to a portion of its interest rate and fair value risks and its crude oil marketing activities, as each is explained below. The derivative financial instrument related to the Partnership's interest rate risk is intended to reduce the Partnership's exposure to increases in the benchmark interest rates underlying the Partnership's variable rate revolving credit facility. The derivative financial instrument related to the Partnership's fair value risks is intended to reduce the Partnership's exposure to changes in the fair value of the fixed rate Senior Notes resulting from changes in interest rates. The Partnership's Upstream Segment uses derivative financial instruments to reduce the Partnership's exposure to fluctuations in the market price of crude oil. By using derivative financial instruments to hedge exposures to changes in interest rates, fair value of fixed rate Senior Notes and crude oil prices, the Partnership exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Partnership, which creates credit risk for the Partnership. When the fair value of a derivative contract is negative, the Partnership owes the counterparty and, therefore, it does not possess credit risk. The Partnership minimizes the credit risk in derivative instruments by entering into transactions with major financial institutions or commodities trading institutions. These derivative financial instruments generally take the form of swaps and forward contracts. Market risk is the adverse effect on the value of a financial instrument that results from a change in interest rates or commodity prices. The market risk associated with interest-rate and commodity-price contracts is managed by establishing and monitoring parameters that limit the type and degree of market risk that may be undertaken.

At December 31, 2001, the Upstream Segment had no open positions on derivative financial contracts.

As of December 31, 2001, the Partnership had in place an interest rate swap agreement to hedge its exposure to increases in the benchmark interest rate underlying its variable rate revolving credit facilities. The Partnership has designated this swap agreement, which hedges exposure to variability in expected future cash flows attributed to changes in interest rates, as a cash flow hedge. The swap agreement is based on a notional amount of $250 million. Under the swap agreement, the Partnership pays a fixed rate of interest of 6.955% and receives a floating rate based on a three month U.S. Dollar LIBOR rate. Since this swap is designated as a cash flow hedge, the changes in fair value, to the extent the swap is effective, are recognized in other comprehensive income until the hedged interest costs are recognized in earnings. During the year ended December 31, 2001, the Partnership recognized $6.8 million in losses, included in interest expense, on the interest rate swap attributable to interest costs occurring in 2001. No gain or loss from ineffectiveness was required to be recognized. The fair value of the interest rate swap agreement was a loss of approximately $20.3 million at December 31, 2001. Approximately $11.7 million of such amount is anticipated to be transferred into earnings over the next twelve months.

As of December 31, 2001, TE Products also had in place 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. The Partnership has designated this swap agreement, which hedges exposure to changes in the fair value of the TE Products Senior Notes, as a fair value hedge. The swap agreement has a notional amount of $210 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 based on a three month U.S. Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51%. Since this swap is designated as a fair value hedge, the changes in fair value are recognized in current earnings. During the year ended December 31, 2001, the Partnership recognized a gain of $1.8 million, included as a component of interest expense, on the interest rate swap. No gain or loss from ineffectiveness was required to be recognized.

During 2001, the Partnership entered into treasury rate lock agreements with a combined notional amount of $400 million to hedge its exposure to increases in the treasury rate that was to be used to establish the fixed interest rate for an anticipated debt offering planned to occur in the fourth quarter of 2001. The debt offering did not occur in 2001. Under the treasury rate lock agreements, the Partnership would pay a fixed rate of interest, and would receive a floating rate based on the three month treasury rate. The treasury rate locks were designated as cash flow hedges. As a result, the changes in fair value, to the extent the treasury rate locks were effective, would be recognized in other comprehensive income until the actual debt offering occurred. Upon completion of the debt offering, the realized gain or loss on the treasury rate locks would be amortized out of accumulated other comprehensive income into interest expense over the life of the debt obligation. During April 2001, a treasury lock with a notional amount of $200 million was terminated and a gain of $1.1 million was realized. The realized gain was recorded as a component of accumulated other comprehensive income. During December 2001, the remaining treasury lock with a notional amount of $200 million was terminated resulting in a realized loss of $1.1 million. The realized loss was recorded as a component of interest expense. The realized gain recorded in April 2001 to accumulated other comprehensive income was reclassified to interest expense in December, upon termination of the treasury lock agreement.

Inventories

Inventories consist primarily of petroleum products and crude oil which are valued at the lower of cost (weighted average cost method) or market. The 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.

Property, Plant and Equipment

Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. Replacements and renewals of minor items of property are charged 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). Upon sale or retirement of properties regulated by the FERC, cost less salvage is normally charged to accumulated depreciation, and no gain or loss is recognized.

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 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.

Capitalization of Interest

The Partnership capitalizes 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 6.46%, 7.45% and 7.01% for 2001, 2000 and 1999, respectively. During the years ended December 31, 2001, 2000 and 1999, the amount of interest capitalized was $4.0 million, $4.6 million and $2.1 million, respectively.

Intangible Assets

Intangible assets at December 31, 2001, consist primarily of production contracts assumed in the acquisition of Jonah Gas Gathering Company ("Jonah") on September 30, 2001, and the fractionation agreement with DEFS. In connection with the acquisition of Jonah, the Partnership assumed contracts that dedicate future production from natural gas wells in the Green River Basin in the State of Wyoming (see Note 3. Acquisitions). 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. The value assigned to intangible assets are amortized over the expected lives of the contracts (approximately 16 years) in proportion to the timing of the expected contractual volumes. At December 31, 2001, the unamortized balance of these production contracts was $219.5 million.

The fractionation agreement with DEFS was entered into in 1998 and is being amortized over a period of 20 years. At December 31, 2001, the unamortized balance of this agreement was $30.9 million. (See Note 4. Related Party Transactions.)

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is amortized on a straight-line basis over the expected periods to be benefited, generally 20 years. Goodwill is presented on the consolidated balance sheets net of accumulated amortization. At December 31, 2001 and 2000, the Partnership had $14.7 million and $4.2 million, respectively, of unamortized goodwill. Amortization expense related to goodwill was $0.9 million and $0.1 million for the years ended December 31, 2001 and 2000, respectively.

In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually. SFAS 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives. The Partnership adopted SFAS 142 effective January 1, 2002. At the date of this report, the Partnership is evaluating the impact of adopting SFAS 142, including whether any transitional impairment losses will be required to be recognized as the cumulative effect of a change in accounting principle. Beginning January 1, 2002, effective with the adoption of SFAS 142, the Partnership will no longer record amortization expense related to goodwill. The goodwill associated with the acquisition of Jonah, which was completed on September 30, 2001, is not being amortized due to the adoption of certain provisions of SFAS 142 (see Note 2. New Accounting Pronouncements).

Income Taxes

The Partnership is a limited partnership. As a result, the Partnership's income or loss for federal income tax purposes is included in the tax return of the individual partners, and may vary substantially from income or loss reported for financial reporting purposes. Accordingly, no recognition has been given to federal income taxes for the Partnership's operations.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Cash Flows

For purposes of reporting cash flows, all liquid investments with maturities at date of purchase of 90-days or less are considered cash equivalents.

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 Limited Partner and Class B Units outstanding (a total of 39.3 million Units for 2001, 33.6 million Units for 2000 and 32.9 million Units for 1999). The general partner's percentage interest in net income is based on its percentage of cash distributions from Available Cash for each year (see Note 10. Quarterly Distributions of Available Cash). The general partner was allocated $23.5 million (representing 21.54%) of net income for the year ended December 31, 2001, $13.9 million (representing 17.96%) of net income for the year ended December 31, 2000, and $9.3 million (representing 12.89%) of net income for the year ended December 31, 1999.

Diluted net income per Unit is similar to the computation of basic net income per Unit above, except that the denominator was increased to include the dilutive effect of outstanding Unit options by application of the treasury stock method. For the years ended December 31, 2001, 2000 and 1999, the denominator was increased by 41,864 Units, 20,926 Units and 12,141 Units, respectively.

Unit Option Plan

The Partnership follows the intrinsic value based method of accounting for its stock-based compensation plans (see Note 11. Unit Option Plan). Under this method, the Partnership records no compensation expense for unit options granted when the exercise price of options granted is equal to the fair market value of the Units on the date of grant.

New Accounting Pronouncements

In July 2001, the FASB issued SFAS No. In July 2001, the FASB issued SFAS No. 141, *Business Combinations*. SFAS 141 requires that the purchase method of accounting be used for all business combinations and specifies that certain acquired intangible assets be reported apart from goodwill. The Partnership adopted SFAS 141 during 2001.

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 requires the Partnership to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development and/or normal use of the assets. The Partnership also records a corresponding asset, which is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Partnership is required to adopt SFAS 143 effective January 1, 2003.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS 144 supercedes SFAS No. 121, *Accounting for Long-Lived Assets and For Long-Lived Assets to be Disposed Of*, but retains its fundamental provisions for reorganizing and measuring impairment losses on long-lived assets held for use and long-lived assets to be disposed of by sale. The Partnership was required to adopt SFAS 144 effective January 1, 2002. The adoption of SFAS 144 did not have a material effect on the financial position, results of operations or cash flows of the Partnership.

NOTE 3. ACQUISITIONS

On July 20, 2000, the Partnership completed an acquisition of ARCO Pipe Line Company ("ARCO"), a wholly-owned subsidiary of Atlantic Richfield Company, for $322.6 million, which included $4.1 million of acquisition related costs other than the purchase price. The purchased assets included ARCO's 50-percent ownership interest in Seaway Crude Pipeline Company ("Seaway"), which 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 areas. The Partnership assumed ARCO's role as operator of this pipeline. The Company also acquired: (i) ARCO's crude oil terminal facilities in Cushing and Midland, Texas, including the line transfer and pumpover business at each location; (ii) an undivided ownership interest in both the Rancho Pipeline, a crude oil pipeline from West Texas to Houston, and the Basin Pipeline, a crude oil pipeline running from Jal, New Mexico, through Midland to Cushing, both of which are operated by another joint owner; and (iii) the receipt and delivery pipelines known as the West Texas Trunk System, which is located around the Midland terminal. The acquisition was accounted for under the purchase method of accounting. Accordingly, the results of the acquisition are included in the consolidated financial statements from July 20, 2000.

In October 2000, the Partnership received a settlement notice from Atlantic Richfield Company for payment of a net aggregate amount of approximately $12.9 million in post-closing adjustments related to the purchase of ARCO. A large portion of the requested adjustment related to an indemnity for payment of accrued income taxes. In August 2001, the Partnership and Atlantic Richfield Company reached a settlement of $11.0 million for the post-closing adjustments. The Partnership recorded the settlement as an increase to the purchase price of ARCO. The Partnership paid the settlement amount to Atlantic Richfield Company on October 15, 2001.

On September 30, 2001, subsidiaries of the Partnership completed the purchase of Jonah from Alberta Energy Company for $359.8 million. The acquisition serves as an entry into the natural gas gathering industry for the Partnership. Goodwill recognized in the purchase amounted to approximately $2.4 million. The acquisition was accounted for under the purchase method of accounting. Accordingly, the results of the acquisition are included in the consolidated financial statements from September 30, 2001. An additional $7.2 million was accrued at December 31, 2001, for final purchase adjustments related primarily to construction projects in progress at the time of closing.

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

Property, plant and equipment	$141,835
Intangible assets (primarily gas transportation contracts)	222,800
Goodwill	2,486
Total assets	367,121
Total liabilities assumed	(489)
Net assets acquired	$366,632

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. The value assigned to intangible assets will be amortized over the expected lives of the contracts (approximately 16 years) in proportion to the timing of expected contractual volumes.

The following table presents the unaudited pro forma results of the Partnership as though the acquisitions of the ARCO and Jonah businesses occurred at the beginning of the respective periods (in thousands, except per Unit amounts). The pro forma results do not include operating efficiencies or revenue growth from historical results.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Years Ended December 31,	
	2001	2000
Revenues	$3,579,684	$3,128,612
Operating income	141,720	107,916
Net income	88,124	61,255
Basic and diluted net income per Limited Partner and Class B Unit	$ 1.76	$ 1.50

On December 31, 2000, the Company completed an acquisition of certain pipeline assets from DEFS for $91.7 million, which included $0.7 million of acquisition related costs. The purchase included two natural gas liquids pipelines in East Texas: the Panola Pipeline, a pipeline from Carthage, Texas, to Mont Belvieu, Texas, and the San Jacinto Pipeline, a pipeline from Carthage to Longview, Texas. A lease of a condensate pipeline from Carthage to Marshall, Texas, was also assumed. All three pipelines originate at DEFS' East Texas Plant Complex in Panola County, Texas. The acquisition of the assets was accounted for under the purchase method of accounting.

NOTE 4. RELATED PARTY TRANSACTIONS

The Partnership has no employees and is managed by the Company, a wholly-owned subsidiary of DEFS. Duke Energy holds an approximate 70% interest in DEFS and Phillips holds the remaining 30%. According to the Partnership Agreements, the Company is entitled to reimbursement of all direct and indirect expenses related to business activities of the Partnership (see Note 1. Partnership Organization).

For the years ended December 31, 2001, 2000, and 1999, direct expenses incurred by the Company in the amount of $68.2 million, $50.4 million, and $49.6 million, respectively, were charged to the Partnership. Substantially all such costs were related to payroll and payroll related expenses. For the years ended December 31, 2001, 2000, and 1999, expenses for administrative service and overhead allocated to the Partnership by Duke Energy and its affiliates amounted to $0.6 million, $0.8 million, and $2.1 million, respectively.

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 $7.4 million, $7.5 million and $7.3 million for the years ended December 31, 2001, 2000 and 1999, respectively. TEPPCO Colorado and DEFS also entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities. 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, $0.9 million and $0.8 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Included with certain crude oil assets purchased from DEFS effective November 1, 1998, was the Wilcox NGL Pipeline located along the Texas Gulf Coast. The Wilcox NGL Pipeline transports NGLs for DEFS from two of their processing plants and is currently supported by a throughput agreement with DEFS through 2005. The fees on the agreement totaled $1.2 million, $1.1 million and $1.1 million for the years ended December 31, 2001, 2000 and 1999, respectively.

On July 20, 2000, the Partnership, through TCTM, acquired a 50-percent ownership interest in Seaway. Phillips owns the remaining 50% interest in Seaway. The Partnership is the operator of this pipeline. During the years ended 2001 and 2000, the Partnership billed to Seaway $7.0 million and $2.9 million, respectively, for direct payroll and payroll related expenses for operating Seaway. Additionally, during the years ended December 31, 2001 and 2000, the Partnership billed to Seaway $2.1 million and $0.9 million, respectively, for indirect management fees for operating Seaway.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Effective May 2001, the Company entered into an agreement with DEFS to commit sole utilization of the Providence terminal to DEFS. The terminal is operated by the Partnership. During the year ended December 31, 2001, DEFS paid the Partnership $1.5 million pursuant to this agreement.

On September 30, 2001, the Partnership completed the acquisition of Jonah. The Jonah assets are managed and operated by employees of DEFS under a contractual arrangement under which DEFS is reimbursed for its actual costs. Certain employees of DEFS also act as officers of TEPPCO GP in order to facilitate management of the Jonah assets by DEFS. These DEFS employees receive no additional compensation from the Partnership for these activities. During the year ended December 31, 2001, the Partnership recognized $0.6 million of expense related to the management of the Jonah assets by DEFS.

NOTE 5. EQUITY INVESTMENTS

Seaway is a partnership between TCTM and Phillips. TCTM purchased its 50-percent ownership interest in Seaway on July 20, 2000 (see Note 3. Acquisitions). The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of the Seaway partnership. From July 20, 2000, through May 2002, TCTM receives 80% of revenue and expense of Seaway. From June 2002 until May 2006, TCTM receives 60% of revenue and expense of Seaway. Thereafter, the sharing ratio becomes 40% of revenue and expense to TCTM.

In August 2000, the Partnership entered into agreements with CMS Energy Corporation and Marathon Ashland Petroleum LLC to form Centennial Pipeline, LLC ("Centennial"). Centennial owns and operates an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to Illinois. Each participant owns a one-third interest in Centennial. During 2001 and 2000, the Partnership contributed approximately $65.0 million and $5.0 million, respectively, for its investment in Centennial. Such amounts are included in the equity investment balance at December 31, 2001 and 2000.

The Partnership uses the equity method of accounting for its investments in Seaway and Centennial. Summarized combined financial information for Seaway as of and for the year ended December 31, 2001, and as of December 31, 2000, and for the period from July 20, 2000, through December 31, 2000, and for Centennial as of and for the year ended December 31, 2001, is presented below (in thousands):

	2001	2000
Current assets	$ 57,368	$ 36,883
Noncurrent assets	528,835	288,191
Current liabilities	31,308	9,220
Long-term debt	128,000	—
Partners' capital	426,895	315,854
Revenues	72,026	31,989
Net income	30,294	12,449

The Partnership's investment in Seaway at December 31, 2001 and 2000, includes an excess investment amount of $25.5 million and $26.4 million, net of accumulated amortization of $1.6 million and $0.7 million, respectively. This excess investment relates to the Partnership's allocation of the purchase price on July 20, 2000, in excess of its proportionate share of the net assets of Seaway. The excess investment is being amortized using the straight-line method over 20 years.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 6. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The major components of inventories were as follows (in thousands):

	December 31,	
	2001	2000
Crude oil	$ 3,783	$14,635
Gasolines	4,548	3,795
Propane	1,096	—
Butanes	1,431	267
Other products	2,866	2,775
Materials and supplies	3,519	3,312
Total	$17,243	$24,784

The costs of inventories did not exceed market values at December 31, 2001 and 2000.

NOTE 7. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment were as follows (in thousands):

	December 31,	
	2001	2000
Land and right of way	$ 92,664	$ 77,798
Line pipe and fittings	822,332	739,372
Storage tanks	130,461	125,890
Buildings and improvements	15,131	13,127
Machinery and equipment	252,393	178,227
Construction work in progress	157,728	66,456
Total property, plant and equipment	$1,470,709	$1,200,870
Less accumulated depreciation and amortization	290,248	251,165
Net property, plant and equipment	$1,180,461	$ 949,705

Depreciation expense on property, plant and equipment was $39.5 million, $33.0 million and $30.7 million for the years ended December 31, 2001, 2000 and 1999, respectively.

NOTE 8. LONG TERM DEBT

Senior Notes

On January 27, 1998, TE Products completed the issuance of $180 million principal amount of 6.45% Senior Notes due 2008, and $210 million principal amount of 7.51% Senior Notes due 2028 (collectively the “Senior Notes”). The 6.45% Senior Notes were issued at a discount and are being accreted to their face value over the term of the notes. The 6.45% Senior Notes due 2008 are not subject to redemption prior to January 15, 2008. The 7.51% 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 Senior Notes do not have sinking fund requirements. Interest on the Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The 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 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 the Partnership's ability to incur additional indebtedness. As of December 31, 2001, TE Products was in compliance with the covenants of the Senior Notes.

On October 4, 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its $210 million principal amount of 7.51% fixed rate Senior Notes. The swap agreement has a notional amount of $210 million and matures in January 2028 to match the principal and maturity of the Senior Notes. Under the swap agreement, TE Products pays a floating rate based on a three month U.S. Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51%.

At December 31, 2001 and 2000, the estimated fair value of the Senior Notes was approximately $362 million and $385 million, respectively. Market prices for recent transactions and rates currently available to the Partnership for debt with similar terms and maturities were used to estimate fair value.

Other Long Term Debt and Credit Facilities

In connection with the purchase of fractionation assets from DEFS as of March 31, 1998, TEPPCO Colorado, a subsidiary of TE Products, received a $38 million bank loan. The interest rate on this loan was 6.53%, which was payable quarterly. The original maturity date was April 21, 2001. This loan was refinanced by the Partnership on July 21, 2000, through the credit facility discussed below.

On May 17, 1999, TE Products entered into a five-year $75 million term loan agreement to finance construction of three new pipelines between TE Products' terminal in Mont Belvieu, Texas and Port Arthur, Texas. This loan was refinanced by the Partnership on July 21, 2000, through the credit facility discussed below.

On May 17, 1999, TE Products entered into a five-year $25 million revolving credit agreement, and TCTM entered into a three-year $30 million revolving credit agreement. Both of the credit facilities were terminated in connection with the refinancing on July 21, 2000, discussed below. TE Products did not make any borrowings under this revolving credit facility. TCTM had a $3 million principal amount outstanding under its revolving credit agreement as of July 21, 2000.

On July 14, 2000, the Partnership entered into a $75 million term loan and a $475 million revolving credit facility ("Three Year Facility"). On July 21, 2000, the Partnership borrowed $75 million under the term loan and $340 million under the Three Year Facility. The funds were used to finance the acquisition of the ARCO assets (see Note 3. Acquisitions) and to refinance existing bank credit facilities, other than the Senior Notes. The term loan was repaid from proceeds received from the issuance of additional Limited Partner Units on October 25, 2000.

On April 6, 2001, the Partnership's Three Year Facility was amended to provide for revolving borrowings of up to $500 million including the issuance of letters of credit of up to $20 million. The term of the revised Three Year Facility was extended to April 6, 2004. The interest rate is based on the Partnership's option of 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 contains restrictive financial covenants that require the Partnership to maintain a minimum level of partners' capital as well as maximum debt-to-EBITDA (earnings before interest expense, income tax expense and depreciation and amortization expense) and minimum fixed charge coverage ratios. On September 28, 2001, the Three Year Facility was amended to extend to December 31, 2001, the time period for the maximum debt-to-EBITDA ratio covenant to allow for the additional debt incurred for the acquisition of Jonah. On November 13, 2001, the Three Year Facility was further amended to require prepayment of outstanding borrowings only upon the receipt of net cash proceeds from asset dispositions or from insurance proceeds in accordance with the terms of the agreement. At such time, certain lenders under the agreement elected to withdraw from the facility, and the available borrowing capacity was reduced to $411 million. As of December 31, 2001, the Partnership was in compliance with the covenants contained in this credit agreement. At December 31, 2001 and 2000, $340.7 million and $446 million was outstanding under the Three Year Facility at a weighted average interest rate of 2.9% and 8.23%, respectively. At December 31, 2001 and 2000, the carrying value of the revolving credit facility approximated its fair value.

On July 21, 2000, the Partnership entered into a three year swap agreement to hedge its exposure to increases in the benchmark interest rate underlying its variable rate revolving credit facilities. On April 6, 2001, the swap agreement was extended until April 6, 2004, to match the maturity of the variable rate credit facility. The swap agreement is based on a notional amount of $250 million. Under the swap agreement, the Partnership pays a fixed rate of interest of 6.955% and receives a floating rate based on a three month U.S. Dollar LIBOR rate. At December 31, 2001 and 2000, the estimated fair value of the swap agreement was a loss of approximately $20.3 million and $10 million, respectively (see Note 2. Use of Derivatives).

Short Term Credit Facilities

On April 6, 2001, the Partnership entered into a 364-day, $200 million revolving credit agreement ("Short-term Revolver"). The interest rate is based on the Partnership's option of 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 contains restrictive financial covenants that require the Partnership to maintain a minimum level of partners' capital as well as maximum debt-to-EBITDA and minimum fixed charge coverage ratios. On September 28, 2001, the Short-term Revolver was amended to extend to December 31, 2001, the time period for the maximum debt-to-EBITDA ratio covenant to allow for the additional debt incurred for the acquisition of Jonah. On November 13, 2001, the Short-term Revolver was further amended to require prepayment of outstanding borrowings only upon the receipt of net cash proceeds from asset dispositions or from insurance proceeds in accordance with the terms of the agreement. At such time, certain lenders under the agreement elected to withdraw from the facility, and the available borrowing capacity was reduced to $164 million. At December 31, 2001, $160 million, included in current liabilities, was outstanding under the Short-term Revolver at a weighted average interest rate of 2.9%. As of December 31, 2001, the Partnership was in compliance with the covenants contained in this credit agreement.

On September 28, 2001, the Partnership entered into a $400 million credit facility with SunTrust Bank ("Bridge Facility"). The Partnership borrowed $360 million under the Bridge Facility for the acquisition of the Jonah assets (see Note 3. Acquisitions). The Bridge Facility is payable in June 2002. During the fourth quarter of 2001, $160 million of the outstanding principal was repaid from the proceeds received from the issuance of the Limited Partner Units in November 2001. The interest rate is based on the Partnership's option of either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreements contain restrictive financial covenants that require the Partnership to maintain a minimum level of partners' capital as well as maximum debt-to-EBITDA and minimum fixed charge coverage ratios. At December 31, 2001, $200 million was outstanding under the Bridge Facility at an interest rate of 3.2%. As of December 31, 2001, the Partnership was in compliance with the covenants contained in this credit agreement.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table summarizes the principal outstanding under the credit facilities of the Partnership as of December 31, 2001 and 2000 (in thousands):

	2001	2000
Short Term Credit Facilities:		
Short-term Revolver, due April 2002	$160,000	$ —
Bridge Facility, due June 2002	200,000	—
Total Short Term Credit Facilities	$360,000	$ —
Long Term Credit Facilities:		
Three Year Facility, due April 2004	$340,658	$446,000
6.45% Senior Notes, due January 2008	179,814	179,784
7.51% Senior Notes, due January 2028	210,000	210,000
Total Long Term Credit Facilities	$730,472	$835,784

NOTE 9. CONCENTRATIONS OF CREDIT RISK

The Partnership’s primary market areas are located in the Northeast, Midwest and Southwest regions of the United States. The Partnership has 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 the Partnership’s overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. The Partnership’s customers’ historical and future credit positions are thoroughly analyzed prior to extending credit. The Partnership manages its 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.

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

NOTE 10. QUARTERLY DISTRIBUTIONS OF AVAILABLE CASH

The Partnership makes quarterly cash distributions of all of its 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 on the portion that cash distributions on a per Unit basis 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%

TEPPCO PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table reflects the allocation of total distributions paid for the years ended December 31, 2001, 2000 and 1999 (in thousands, except per Unit amounts).

	Years Ended December 31,		
	2001	2000	1999
Limited Partner Units	$ 73,961	$59,943	$53,650
General Partner Ownership Interest	1,273	685	609
General Partner Incentive	20,257	12,938	7,650
Total Partners' Capital Cash Distributions	95,491	73,566	61,909
Class B Units	8,421	7,833	6,651
Minority Interest	500	832	699
Total Cash Distributions Paid	$104,412	$82,231	$69,259
Total Cash Distributions Paid Per Unit	$ 2.15	$ 2.00	$ 1.85

On February 8, 2002, the Partnership paid a cash distribution of $0.575 per Limited Partner Unit and Class B Unit for the quarter ended December 31, 2001. The fourth quarter 2001 cash distribution totaled $33.5 million.

NOTE 11. UNIT OPTION PLAN

During 1994, the Company adopted the Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan ("1994 LTIP"). The 1994 LTIP provides key employees with an incentive award whereby a participant is granted an option to purchase Limited Partner Units together with a stipulated number of Performance Units. Under the provisions of the 1994 LTIP, no more than one million options and two million Performance Units may be granted. Each Performance Unit creates a credit to a participant's Performance Unit account when earnings exceed a threshold. When earnings for a calendar year (exclusive of certain special items) exceed the threshold, the excess amount is credited to the participant's Performance Unit account. The balance in the account may be used to exercise Limited Partner 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. Under the agreement for such Limited Partner Unit options, the options become exercisable in equal installments over periods of one, two, and three years from the date of the grant. Options may also be exercised by normal means once vesting requirements are met. A summary of Performance Units and Limited Partner Unit options granted under the terms of the 1994 LTIP is presented below:

	Performance Units	Earnings Threshold	Expiration Year
Performance Unit Grants:			
1994	80,000	$ 1.00	2006
1995	70,000	$ 1.25	2007
1997	11,000	$1.875	2009

	Options Outstanding	Options Exercisable	Exercise Range
Limited Partner Unit Options:			
Outstanding at December 31, 1998	190,796	72,359	$13.81-$21.66
Granted	162,000	—	$25.25
Became exercisable	—	40,737	$21.66-$25.69
Exercised	(14,000)	(14,000)	$13.81-$14.34
Outstanding at December 31, 1999	338,796	99,096	$13.81-$25.69
Forfeited	(28,000)	(4,000)	$25.25-$25.69
Became exercisable	—	85,365	$21.66-$25.69
Exercised	(19,932)	(19,932)	$13.81-$14.34
Outstanding at December 31, 2000	290,864	160,529	$13.81-$25.69
Forfeited	(10,666)	—	$25.25
Became exercisable	—	81,669	$25.25-$25.69
Exercised	(98,376)	(98,376)	$13.81-$25.69
Outstanding at December 31, 2001	181,822	143,822	$13.81-$25.69

As discussed in Note 2, the Partnership uses 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 the Partnership's Limited Partner Units on the date of grant. Accordingly, no compensation expense was recognized 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 totaled $226,152, $202,634 and $99,076 during 1999, 2000 and 2001, respectively. The disclosures as required by SFAS 123 are not representative of the effects on pro forma net income for future years as options vest over several years and additional awards may be granted in subsequent years.

For purposes of determining compensation costs using the provisions of SFAS 123, the fair value of 1999 option grants were determined using the Black-Scholes option-valuation model. The key input variables used in valuing the options were:

	1999
Risk-free interest rate	4.7%
Dividend yield	7.6%
Unit price volatility	23%
Expected option lives	6 years

NOTE 12. LEASES

The Partnership utilizes leased assets in several areas of its operations. Total rental expense during 2001, 2000 and 1999 was $10.8 million, $10.7 million and $8.7 million, respectively. The minimum rental payments under the Partnership's various operating leases for the years 2002 through 2006 are $8.8 million, $7.7 million, $7.1 million, $6.1 million and $4.9 million, respectively. Thereafter, payments aggregate $1.4 million through 2007.

NOTE 13. EMPLOYEE BENEFITS

Retirement Plans

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 ("Duke Energy RCBP"), which is a noncontributory, trustee-administered pension plan. In addition, certain executive officers participated in the Duke Energy Executive Cash Balance Plan (“Duke Energy ECBP”), which is a noncontributory, nonqualified, defined benefit retirement plan. The Duke Energy ECBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans. Effective January 1, 1999, the benefit formula for all eligible employees was 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. As part of the change in ownership, the Company is no longer responsible for the funding of the liabilities associated with these plans.

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 RCBP and the Duke Energy ECBP previously in effect prior to April 1, 2000.

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2001 and 2000, and for the Duke Energy RCBP and the Duke Energy ECBP for the years ended December 31, 2000 and 1999 were as follows (in thousands):

	2001	2000	1999
Service cost benefit earned during the year	$2,419	$2,054	$ 1,651
Interest cost on projected benefit obligation	129	782	2,666
Expected return on plan assets	(166)	(663)	(2,243)
Amortization of prior service cost	8	—	2
Amortization of net transition liability	—	4	15
Recognized net actuarial loss	—	—	285
Net pension benefits costs	$2,390	$2,177	$ 2,376

Other Postretirement Benefits

Prior to April 1, 2000, the Company’s employees were provided with certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis through Duke Energy (“Duke Energy OPB”). Employees became eligible for these benefits if they had met certain age and service requirements at retirement, as defined in the plans. As part of the change in ownership, the Company is no longer responsible for the funding of the liabilities associated with these plans. Effective January 1, 2001, the Company provided its own plan for health care benefits for retired employees (“TEPPCO OPB”).

The Company provides a fixed dollar contribution towards retired employee medical costs. The fixed dollar contribution does not increase from year to year. The retiree pays all health care cost increases due to medical inflation.

The components of net postretirement benefits cost for the Duke Energy OPB for the years ended December 31, 2000 and 1999, and for the TEPPCO OPB for the year ended December 31, 2001, were as follows (in thousands):

	2001	2000	1999
Service cost benefit earned during the year	$ 99	$ 39	$ 172
Interest cost on accumulated postretirement benefit obligation	113	134	500
Expected return on plan assets	—	(85)	(299)
Amortization of prior service cost	126	(96)	(384)
Amortization of net transition liability	—	54	217
Net postretirement benefits costs	$338	$ 46	$ 206

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The weighted average assumptions used in the actuarial computations for the retirement plans and other postretirement benefit plans for the years ended December 31, 2001 and 2000 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
Discount rate	7.25%	7.50%	7.25%	7.50%
Increase in compensation levels	5.06%	4.50%	—	—
Expected long-term rate of return on plan assets	9.00%	9.25%	—	—

The following table sets forth the Company's pension and other postretirement benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2001 and 2000.

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000(1)
Change in benefit obligation				
Benefit obligation at beginning of year	$1,518	$ —	$ —	$—
Service cost	2,419	1,518	99	—
Interest cost	129	(1)	113	—
Plan amendments	62	—	1,508	—
Actuarial (gain)/loss	(136)	1	57	—
Retiree contributions	—	—	9	—
Benefits paid	(206)	—	(5)	—
Benefit obligation at end of year	$3,786	$ 1,518	$ 1,781	$—
Change in plan assets				
Fair value of plan assets at beginning of year	$ —	$ —	$ —	$—
Actual return on plan assets	(37)	—	—	—
Retiree contributions	—	—	9	—
Employer contributions	4,202	—	(4)	—
Benefits paid	(206)	—	(5)	—
Fair value of plan assets at end of year	$3,959	$ —	$ —	$—
Reconciliation of funded status				
Funded status	$ 173	$(1,518)	$(1,781)	$—
Unrecognized prior service cost	54	—	1,381	—
Unrecognized actuarial loss	68	—	57	—
Net amount recognized	$ 295	$(1,518)	$ (343)	$—

(1) The TEPPCO OPB became effective on January 1, 2001.

Other Plans

Duke Energy also sponsors an employee savings plan, which covers substantially all employees. Plan contributions on behalf of the Company of $3.1 million, $2.2 million and $2.2 million were expensed in 2001, 2000 and 1999, respectively.

NOTE 14. COMMITMENTS AND CONTINGENCIES

In the fall of 1999 and on December 1, 2000, the Company and the Partnership were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, in *Ryan E. McCleery and Marcia S. McCleery, et. al. v. Texas Eastern Corporation, et. al. (including the Company and Partnership) and Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et. al. (including the Company and Partnership).* In both cases, the plaintiffs contend, among other things, that the Company 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. The Company has filed an answer to both complaints, denying the allegations, as well as various other motions. These cases are in the early stages of discovery and are not covered by insurance. The Company is defending itself vigorously against the lawsuits. The plaintiffs have not stipulated the amount of damages that they are seeking in the suit. The Partnership cannot estimate the loss, if any, associated with these pending lawsuits.

On December 21, 2001, the Partnership was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, in *Rebecca L. Grisham et. al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that the defendant's pipeline, which crosses the plaintiff's property, leaked toxic products onto the plaintiff's property. The plaintiffs further contend that this leak caused damages to the plaintiffs. The Partnership has filed an answer to the plaintiff's petition denying the allegations. The plaintiffs have not stipulated the amount of damages they are seeking in the suit. The Partnership is defending itself vigorously against the lawsuit. The Partnership cannot estimate the damages, if any, associated with this pending lawsuit, however, this case is covered by insurance.

In addition to the litigation discussed above, the Partnership has 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. The Company believes that the outcome of such lawsuits and other proceedings will not individually or in the aggregate have a material adverse effect on the Partnership's consolidated financial condition, results of operations or cash flows.

In February 2002, a producer on the Jonah Gas Gathering System ("Jonah System") notified Alberta Energy Company that it has a right to acquire all or a portion of the assets comprising the Jonah System. This claim is based upon an alleged right of first refusal contained in a gas gathering agreement between the producer and Jonah. Subsidiaries of Alberta Energy have agreed to indemnify the Partnership against losses resulting from the breach of representations concerning the absence of third party rights in connection with the acquisition of the entity that owns the Jonah System. The Partnership believes that it has adequate legal defenses to the producer's claim and that no right of first refusal on any of the underlying Jonah System assets has been triggered.

The operations of the Partnership are subject to federal, state and local laws and regulations governing the discharge of materials into the environment otherwise relating to environmental protection. 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 the Partnership believes its operations are in material compliance with applicable environmental laws and regulations, risks of significant costs and liabilities are inherent in pipeline operations, and there can be no assurance 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 its operations, could result in substantial costs and liabilities to the Partnership. The Company does not anticipate that changes in environmental laws and regulations will have a material adverse effect on the Partnership's financial position, results of operations or cash flows in the near term.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In 1994, the Partnership and the Indiana Department of Environmental Management ("IDEM") entered into an Agreed Order that resulted in the implementation of a remediation program for groundwater contamination attributable to the Partnership's operations at the Seymour, Indiana, terminal. A Feasibility Study, which includes the Partnership's proposed remediation program, was approved by IDEM in 1999. IDEM is expected to issue a Record of Decision formally approving the remediation program. After the Record of Decision is issued, the Partnership will enter into a subsequent Agreed Order for the continued operation and maintenance of the remediation program. The Partnership has an accrued liability of $0.6 million at December 31, 2001, for future remediation costs at the Seymour terminal. In the opinion of the Company, the completion of the remediation program will not have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

In 1994, the Partnership was issued a compliance order from the Louisiana Department of Environmental Quality ("LDEQ") relative to environmental contamination at the Partnership's Arcadia, Louisiana, facility. This contamination may be attributable to the operations of the Partnership, as well as adjacent petroleum terminals operated by other companies. In 1999, the Partnership's Arcadia facility and the adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this containment phase. In the opinion of the Company, the completion of the remediation program that is proposed by the Partnership will not have a future material adverse effect on the Partnership's financial condition, results of operations or cash flows.

During 2001, the Partnership accrued $8.6 million to complete environmental remediation activities at certain of the sites owned by TCTM and its subsidiaries. In establishing this accrual, the Partnership expensed $4.4 million for these environmental remediation costs and recorded a receivable of $4.2 million for the remainder. The receivable is based on a contractual indemnity obligation for specified environmental liabilities owed by DEFS to the Partnership in connection with the Partnership's acquisition of the Upstream Segment from DEFS in November 1998. Under this indemnity obligation, the Partnership is responsible for the first $3.0 million in specified environmental liabilities, with DEFS becoming responsible for those environmental liabilities in excess of $3.0 million, up to a maximum amount of $25.0 million. At December 31, 2001, an accrual of $6.4 million remains outstanding related to TCTM environmental remediation activities. The majority of the indemnified costs relate to remediation activities at the Velma crude oil site in Stephens County, Oklahoma, attributable to operations prior to the Partnership's acquisition of the Upstream Segment. Remediation activities at the Velma crude oil site are being conducted according to a work plan approved by the Oklahoma Corporation Commission. In the opinion of the Company, the completion of remediation programs associated with this release will not have a future material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Rates of interstate oil pipeline companies, like the Partnership, are currently regulated by the FERC, primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the change from year to year in the Producer Price Index for finished goods less 1% ("PPI Index"). In the alternative, interstate 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 the oil pipeline company that the rate is acceptable ("Settlement Rates").

On May 11, 1999, TE Products filed an application with the FERC requesting permission to charge Market-Based Rates for substantially all refined products transportation tariffs. On July 31, 2000, the FERC issued an order granting TE Products Market-Based Rates in certain markets and set for hearing TE Products' application for Market-Based Rates in certain destination markets and origin markets. After the matter was set for hearing, TE Products and the protesting shippers entered into a settlement agreement resolving their respective differences. On April 25, 2001, the FERC issued an order approving the offer of settlement. As a result of the settlement, TE Products recognized approximately $1.7 million of previously deferred transportation revenue in the second quarter of 2001. As a part of the settlement, TE Products withdrew the application for Market-Based Rates to the Little Rock, Arkansas, Arcadia and Shreveport-Arcadia, Louisiana, destination markets, which are currently subject to the PPI Index. As a result, the Partnership made refunds of approximately $1.0 million in the third quarter of 2001 for those destination markets.

Centennial has entered into credit facilities totaling $150 million. The proceeds were used to fund construction and conversion costs of its pipeline system. TE Products has guaranteed one-third of the debt of Centennial up to a maximum amount of $50 million.

Substantially all of the petroleum products transported and stored by the Partnership are owned by the Partnership's customers. At December 31, 2001, TCTM and TE Products had approximately 3.8 million barrels and 19.7 million barrels, respectively, of products in its custody owned by customers. The Partnership is obligated for the transportation, storage and delivery of such products on behalf of its customers. The Partnership maintains insurance adequate to cover product losses through circumstances beyond its control.

NOTE 15. SEGMENT DATA

The Partnership has 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 intercompany eliminations and assets held by the Partnership that have not been allocated to any reporting segment of the Partnership.

Effective January 1, 2002, the Partnership realigned its three business segments in order to separate and better measure the performance of its natural gas and NGL operations from its crude oil operations. The fractionation of NGLs, which was previously reflected as part of the Downstream Segment, was shifted to the Midstream Segment. The operation of NGL pipelines, which was previously reflected as part of the Upstream Segment, was also shifted to the Midstream Segment. The year-to-year comparisons have been adjusted to conform to the current presentation.

The Partnership's Downstream Segment includes the interstate transportation, storage and terminaling of petroleum products and LPGs and intrastate transportation of petrochemicals. Revenues are derived from transportation and storage of refined products and LPGs, storage and short-haul shuttle transportation of LPGs at the Mont Belvieu, Texas, complex, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The Partnership's Downstream Segment, operating through TE Products, is one of the largest pipeline common carriers of refined petroleum products and LPGs in the United States. TE Products owns and operates a pipeline system extending from southeast Texas through the central and midwestern United States to the northeastern United States.

The Partnership's Upstream Segment includes: gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas and the Rocky Mountain region. On July 20, 2000, the Partnership acquired certain assets from ARCO (see Note 3. Acquisitions). The acquisition was accounted for under the purchase method of accounting. The results of the acquisition have been included in the Partnership's Upstream Segment since the purchase on July 20, 2000. The Upstream Segment also includes the equity earnings from the Partnership's investment in Seaway. Seaway is a large diameter pipeline that transports crude oil from the U.S. Gulf Coast to Cushing, Oklahoma, a central crude oil distribution point for the Central United States.

The Partnership's Midstream Segment includes the fractionation of NGLs in Colorado; operating two trunkline NGL pipelines in South Texas and two NGL Pipelines in East Texas; and the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, which was acquired by subsidiaries of the Partnership on September 30, 2001, from Alberta Energy Company (see Note 3. Acquisitions). The acquisition was accounted for under the purchase method of accounting. The results of operations of the Jonah acquisition are included in periods subsequent to September 30, 2001.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The accounting policies of the segments are the same as those described in the summary of significant accounting policies discussed above (see Note 2. Summary of Significant Accounting Policies).

The following table includes financial information by reporting segment for the years ended December 31, 2001, 2000 and 1999 (in thousands):

	Year Ended December 31, 2001					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Revenues	$264,233	$3,255,260	$ 37,242	$3,556,735	$ (322)	$3,556,413
Operating expenses, including power	119,858	3,228,507	11,482	3,359,847	(322)	3,359,525
Depreciation and amortization expense	26,699	9,263	9,937	45,899	—	45,899
Operating income	117,676	17,490	15,823	150,989	—	150,989
Equity earnings	(1,149)	18,547	—	17,398	—	17,398
Other income, net	1,537	1,990	74	3,601	—	3,601
Earnings before interest	$118,064	$ 38,027	$ 15,897	$ 171,988	$ —	$ 171,988
Total assets	$844,036	$ 694,934	$541,195	$2,080,165	$(14,817)	$2,065,348

	Year Ended December 31, 2000					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Revenues	$229,234	$2,844,245	$ 14,462	$3,087,941	$ —	$3,087,941
Operating expenses, including power	118,065	2,824,265	2,423	2,944,753	—	2,944,753
Depreciation and amortization expense	25,728	6,282	3,153	35,163	—	35,163
Operating income	85,441	13,698	8,886	108,025	—	108,025
Equity earnings	—	12,214	—	12,214	—	12,214
Other income, net	1,651	461	237	2,349	—	2,349
Earnings before interest	$ 87,092	$ 26,373	$ 9,123	$ 122,588	$ —	$ 122,588
Total assets	$714,233	$ 752,581	$156,662	$1,623,476	$(666)	$1,622,810

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31, 1999					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Revenues	$222,915	$1,698,490	$13,478	$1,934,883	$ —	$1,934,883
Operating expenses, including power	112,941	1,687,159	2,037	1,802,137	—	1,802,137
Depreciation and amortization expense	25,094	4,423	3,139	32,656	—	32,656
Operating income	84,880	6,908	8,302	100,090	—	100,090
Equity earnings	—	—	—	—	—	—
Other income, net	1,471	525	200	2,196	—	2,196
Earnings before interest	$ 86,351	$ 7,433	$ 8,502	$ 102,286	$ —	$ 102,286
Total assets	$680,433	$ 297,007	$66,353	$1,043,793	$(2,420)	$1,041,373

The following table reconciles the segments total to consolidated net income (in thousands):

	Years Ended December 31,		
	2001	2000	1999
Earnings before interest	$171,988	$122,588	$102,286
Interest expense	(66,057)	(48,982)	(31,563)
Interest capitalized	4,000	4,559	2,133
Minority interest	(800)	(789)	(736)
Net income	$109,131	$ 77,376	$ 72,120

NOTE 16. COMPREHENSIVE INCOME

SFAS 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 year ended December 31, 2001, the components of comprehensive income were due to the interest rate swap related to its variable rate revolving credit facility. The table below reconciles reported net income to total comprehensive income for the year ended December 31, 2001 (in thousands).

Net income	$109,131
Cumulative effect attributable to adoption of SFAS 133 (see Note 2. Use of Derivatives)	(10,103)
Net loss on cash flow hedges	(10,221)
Total comprehensive income	$ 88,807

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

Balance at December 31, 2000	$ —
Cumulative effect of accounting change	(10,103)
Net loss on cash flow hedges	(10,221)
Balance at December 31, 2001	$(20,324)

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 17. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Under the Partnership's shelf registration statement on Form S-3 filed with the Securities and Exchange Commission on February 12, 2002, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, the Partnership's significant operating subsidiaries (the "Guarantor Subsidiaries"), may issue unconditional guarantees of senior or subordinated debt securities of the Partnership in the event that the Partnership issues such securities from time to time under the registration statement. If issued, the guarantees will be full, unconditional and joint and several.

The following supplemental condensed consolidating financial information reflects the separate accounts of the Partnership, the combined accounts of the Guarantor Subsidiaries (including Jonah for all periods and dates from and after September 30, 2001, the date Jonah became a subsidiary of the Partnership), the combined accounts of the other non-guarantor subsidiaries of the Partnership, the combined consolidating adjustments and eliminations and the consolidated Partnership accounts for the dates and periods indicated. For purposes of the following consolidating information, the Partnership's and Guarantor Subsidiaries' investments in their respective subsidiaries are accounted for by the equity method of accounting.

December 31, 2001	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 3,100	$ 59,730	$223,345	$ (2,695)	$ 283,480
Property, plant and equipment — net	—	849,978	330,483	—	1,180,461
Equity investments	669,370	309,080	222,815	(909,041)	292,224
Intercompany notes receivable	700,564	11,269	7,404	(719,237)	—
Other assets	3,853	244,448	65,386	(4,504)	309,183
Total assets	$1,376,887	$1,474,505	$849,433	$(1,635,477)	$2,065,348
Liabilities and partners' capital					
Current liabilities	$ 367,094	$ 361,547	$310,476	$ (370,275)	$ 668,842
Long term debt	340,658	389,814	—	—	730,472
Intercompany notes payable	—	45,410	294,801	(340,211)	—
Other long term liabilities and minority interest	—	8,364	231	8,628	17,223
Redeemable Class B Units held by related party	105,630	—	—	—	105,630
Total partners' capital	563,505	669,370	243,925	(933,619)	543,181
Total liabilities and partners' capital	$1,376,887	$1,474,505	$849,433	$(1,635,477)	$2,065,348

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

December 31, 2000	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 6,083	$ 52,773	$315,488	$ (10,947)	$ 363,397
Property, plant and equipment — net	—	640,657	309,048	—	949,705
Equity investments	420,433	202,811	236,232	(617,828)	241,648
Intercompany notes receivable	441,836	—	—	(441,836)	—
Other assets	5,322	15,385	48,475	(1,122)	68,060
Total assets	$873,674	$911,626	$909,243	$(1,071,733)	$1,622,810
Liabilities and partners' capital					
Current liabilities	$ 7,206	$ 45,085	$318,049	$ (12,069)	$ 358,271
Long term debt	446,000	389,784	—	—	835,784
Intercompany notes payable	—	48,037	393,799	(441,836)	—
Other long term liabilities and minority interest	—	3,991	—	4,296	8,287
Redeemable Class B Units held by related party	105,411	—	—	—	105,411
Total partners' capital	315,057	424,729	197,395	(622,124)	315,057
Total liabilities and partners' capital	$873,674	$911,626	$909,243	$(1,071,733)	$1,622,810

Year Ended December 31, 2001	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$273,379	$3,283,356	$ (322)	$3,556,413
Costs and expenses	—	152,558	3,253,188	(322)	3,405,424
Operating income	—	120,821	30,168	—	150,989
Interest expense — net	(40,143)	(30,605)	(31,452)	40,143	(62,057)
Equity earnings	109,131	18,178	18,547	(128,458)	17,398
Other income — net	40,143	1,537	2,064	(40,143)	3,601
Income before minority interest	109,131	109,931	19,327	(128,458)	109,931
Minority interest	—	—	—	(800)	(800)
Net income	$109,131	$109,931	$ 19,327	$(129,258)	$ 109,131

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Year Ended December 31, 2000	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$229,234	$2,858,707	$ —	$3,087,941
Costs and expenses	—	143,793	2,836,123	—	2,979,916
Operating income	—	85,441	22,584	—	108,025
Interest expense — net	(17,773)	(27,572)	(16,851)	17,773	(44,423)
Equity earnings	77,376	18,602	12,214	(95,978)	12,214
Other income — net	17,773	1,694	655	(17,773)	2,349
Income before minority interest	77,376	78,165	18,602	(95,978)	78,165
Minority interest	—	—	—	(789)	(789)
Net income	$ 77,376	$ 78,165	$ 18,602	$(96,767)	$ 77,376

Year Ended December 31, 1999	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$222,915	$1,711,968	$ —	$1,934,883
Costs and expenses	—	138,035	1,696,758	—	1,834,793
Operating income	—	84,880	15,210	—	100,090
Interest expense — net	—	(26,682)	(2,748)	—	(29,430)
Equity earnings	72,120	13,188	—	(85,308)	—
Other income — net	—	1,470	726	—	2,196
Income before minority interest	72,120	72,856	13,188	(85,308)	72,856
Minority interest	—	—	—	(736)	(736)
Net income	$72,120	$ 72,856	$ 13,188	$(86,044)	$ 72,120

Year Ended December 31, 2001	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	$ 109,131	$ 109,931	$ 19,327	$(129,258)	$ 109,131
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	31,226	14,673	—	45,899
Equity earnings, net of distributions	(5,219)	10,131	13,417	(3,952)	14,377
Changes in assets and liabilities and other	2,874	16,850	(20,783)	800	(259)
Net cash provided by operating activities	106,786	168,138	26,634	(132,410)	169,148
Cash flows from investing activities	(498,711)	(514,178)	(43,687)	498,711	(557,865)
Cash flows from financing activities	391,925	340,529	20,947	(366,301)	387,100
Net increase (decrease) in cash and cash equivalents	—	(5,511)	3,894	—	(1,617)
Cash and cash equivalents at beginning of period	—	9,166	17,930	—	27,096
Cash and cash equivalents at end of period	$ —	$ 3,655	$ 21,824	$ —	$ 25,479

Table of Contents

Year Ended December 31, 2000	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	$ 77,376	$ 78,165	$ 18,602	$ (96,767)	$ 77,376
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	25,728	9,435	—	35,163
Equity earnings, net of distributions	4,025	(1,962)	(10,260)	(1,887)	(10,084)
Changes in assets and liabilities and other	7,242	1,046	845	(3,543)	5,590
Net cash provided by operating activities	88,643	102,977	18,622	(102,197)	108,045
Cash flows from investing activities	(535,048)	(67,225)	(434,113)	542,192	(494,194)
Cash flows from financing activities	446,405	(42,870)	417,112	(439,995)	380,652
Net increase (decrease) in cash and cash equivalents	—	(7,118)	1,621	—	(5,497)
Cash and cash equivalents at beginning of period	—	16,284	16,309	—	32,593
Cash and cash equivalents at end of period	$ —	$ 9,166	$ 17,930	$ —	$ 27,096

Year Ended December 31, 1999	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	$ 72,120	$ 72,856	$ 13,188	$(86,044)	$ 72,120
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	25,094	7,562	—	32,656
Equity earnings, net of distributions	(3,561)	(5,144)	—	9,098	393
Changes in assets and liabilities and other	369	451	(2,917)	(2)	(2,099)
Net cash provided by operating activities	68,928	93,257	17,833	(76,948)	103,070
Cash flows from investing activities	—	(66,282)	(10,359)	—	(76,641)
Cash flows from financing activities	(68,928)	(44,628)	(4,651)	76,948	(41,259)
Net increase (decrease) in cash and cash equivalents	—	(17,653)	2,823	—	(14,830)
Cash and cash equivalents at beginning of period	—	33,937	13,486	—	47,423
Cash and cash equivalents at end of period	$ —	$ 16,284	$ 16,309	$ —	$ 32,593

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 18. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per Unit amounts)			
2001(1)				
Operating revenues	$785,235	$1,073,682	$990,816	$706,680
Operating income	36,306	53,069	27,121	34,493
Net income	25,735	43,038	19,092	21,266
Basic income per Limited Partner and Class B Unit	$ 0.55	$ 0.90	$ 0.35	$ 0.40
Diluted income per Limited Partner and Class B Unit (1)	$ 0.55	$ 0.89	$ 0.35	$ 0.40
2000(2)				
Operating revenues	$750,692	$ 747,704	$749,898	$839,647
Operating income	30,767	20,151	21,907	35,200
Net income	23,881	13,570	17,189	22,736
Basic and diluted income per Limited Partner and Class B Unit (2)	$ 0.60	$ 0.35	$ 0.41	$ 0.53

(1) Per Unit calculation includes 2,000,000 Limited Partner Units issued in February 2001, 250,000 Limited Partner Units issued in March 2001, and 5,500,000 Limited Partner Units issued in November 2001.

(2) Per Unit calculation includes 3,700,000 Limited Partner Units issued on October 25, 2000.

NOTE 19. SUBSEQUENT EVENTS

On January 9, 2002, the Partnership announced a definitive agreement to acquire the Chaparral and Quanah pipelines from Diamond-Koch II, L.P. and Diamond-Koch III, L.P. for approximately $130 million. The transaction closed on March 1, 2002, at a cost of approximately $132 million. The purchase was funded by a drawdown of the Partnership's Three Year Facility.

In January and February 2002, $25 million and $15 million was drawn down on the Three Year Facility and the Bridge Facility, respectively.

On February 20, 2002, the Partnership received $494.6 million in net proceeds from the issuance of $500 million principal amount of 7.625% Senior Notes due 2012. The Senior Notes may be redeemed at any time at the option of the Partnership 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 proceeds from the offering were used to reduce the outstanding balances of the credit facilities (see Note 8. Long Term Debt). The repayments included $160 million outstanding on the Short-term Revolver, $215 million outstanding on the Bridge Facility and $115.7 million outstanding on the Three Year Facility. The Partnership's Guarantor Subsidiaries issued unconditional guarantees of these Senior Notes (see Note 17. Supplemental Condensed Consolidating Financial Information).

Table of Contents

INDEX TO EXHIBITS

Exhibit Number	Description
23.1*	Consent of KPMG LLP.

* Filed herewith.

EXHIBIT 23.1

INDEPENDENT AUDITORS' CONSENT

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

We consent to the incorporation by reference in the registration statements (No. 33-81976) and (No. 333-86650) on Form S-3 and the registration statement (No. 333-82892) on Form S-8 of TEPPCO Partners, L.P. of our report dated January 17, 2002, except as to Note 15, which is as of May 30, 2002, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. as of December 31, 2001 and 2000 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, 2001, which report appears in the December 31, 2001 annual report on Form 10-K/A of TEPPCO Partners, L.P. dated June 3, 2002.

Our report on the consolidated financial statements refers to a change in the method of accounting for derivative financial instruments and hedging activities and the adoption of Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations* and certain provisions of SFAS No. 142, *Goodwill and Other Intangible Assets* in 2001.

KPMG LLP

Houston, Texas
June 3, 2002