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

FORM 10-K

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

For the fiscal year ended December 31, 2007

OR

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

For the transition period from __________ to __________.

Commission File Number 1-10403

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

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

1100 Louisiana Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices, including zip code)

(713) 381-3636
(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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No o

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

At June 30, 2007, the aggregate market value of the registrant's Limited Partner Units held by non-affiliates was $3.2 billion, which was computed using the average of the high and low sales prices of the Limited Partner Units on June 30, 2007.

Limited Partner Units outstanding as of February 1, 2008: 94,766,431.

Documents Incorporated by Reference: **None.**

TEPPCO PARTNERS, L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "*we*," "*us*," "*our*" or "*TEPPCO*" are intended to mean the business and operations of TEPPCO Partners, L.P. and its consolidated subsidiaries.

References to "*TE Products*," "*TCTM*" and "*TEPPCO Midstream*" mean TE Products Pipeline Company, LLC, TCTM, L.P., and TEPPCO Midstream Companies, LLC, our subsidiaries. Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "*Operating Companies.*"

References to "*General Partner*" mean Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and owned by Enterprise GP Holdings L.P., a publicly traded partnership, controlled indirectly by EPCO, Inc.

References to "*TEPPCO GP*" mean TEPPCO GP, Inc., our subsidiary, which is the general partner or manager of the Operating Companies.

References to "*Enterprise GP Holdings*" mean Enterprise GP Holdings L.P., a publicly traded partnership that owns our General Partner and Enterprise Products GP, LLC.

References to "*Enterprise Products Partners*" mean Enterprise Products Partners L.P., and its consolidated subsidiaries, a publicly traded Delaware limited partnership, which is an affiliate of ours.

References to "*EPCO*" mean EPCO, Inc., a privately-held company that is affiliated with our General Partner. Dan L. Duncan is the Chairman and controlling shareholder of EPCO.

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

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

References to "*DFI*" mean Duncan Family Interests, Inc. and "*DFIGP*" mean DFI GP Holdings L.P. DFI and DFIGP are private company affiliates of EPCO. Enterprise GP Holdings acquired its ownership interests in us and our General Partner from DFI and DFIGP.

References to "*Dan Duncan LLC*" mean Dan Duncan LLC, a privately held company that owns EPE Holdings. Dan L. Duncan owns and controls Dan Duncan LLC.

References to "*Duncan Energy Partners*" mean Duncan Energy Partners L.P. and its consolidated subsidiaries, a publicly traded Delaware limited partnership and a consolidated subsidiary of Enterprise Products Partners.

We, Enterprise Products Partners, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings, Duncan Energy Partners, DFI, DFIGP and our General Partner are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO and the controlling member of Dan Duncan LLC.

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

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The matters discussed in this Annual Report on Form 10-K (this "Report") include "forward-looking statements." All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical facts are forward-looking statements. The words "proposed", "anticipate", "potential", "may", "will", "could", "should", "expect", "estimate", "believe", "intend", "plan", "seek" and similar expressions are intended to identify forward-looking statements. Without limiting the broader description of forward-looking statements above, we specifically note that statements included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as future distributions, estimated future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strengths, goals, expansion and growth of our business and operations, plans, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. While we believe our expectations reflected in these forward-looking statements are reasonable, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including general economic, market or business conditions, the opportunities (or lack thereof) that may be presented to and pursued by us, competitive actions by other pipeline or energy transportation companies, changes in laws or regulations and other factors, many of which are beyond our control. For example, the demand for refined products is dependent upon the price, prevailing economic conditions and demographic changes in the markets served, trucking and railroad freight, agricultural usage and military usage; the demand for propane is sensitive to the weather and prevailing economic conditions; the demand for petrochemicals is dependent upon prices for products produced from petrochemicals; the demand for crude oil and petroleum products is dependent upon the price of crude oil and the products produced from the refining of crude oil; and the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled. Further, the success of our new marine transportation business is dependent upon, among other things, our ability to effectively assimilate and provide for the operation of that business and maintain key personnel and customer relationships. We are also subject to regulatory factors such as the amounts we are allowed to charge our customers for the services we provide on our regulated pipeline systems and the cost and ability of complying with government regulations of the marine transportation industry. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to or effect on us or our business or operations. Also note that we provide additional cautionary discussion of risks and uncertainties under the captions "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Report.

The forward-looking statements contained in this Report speak only as of the date hereof. Except as required by the federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Report and in our future periodic reports filed with the U.S. Securities and Exchange Commission ("SEC"). In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Report may not occur.

PART I

Items 1 and 2. *Business and Properties*

General

We are a publicly traded Delaware limited partnership formed in March 1990 and our limited partner units ("Units") are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "TPP". We are one of the largest common carrier pipelines of refined products and liquefied petroleum gases ("LPGs") in the United States. In addition, we own and operate petrochemical and natural gas liquids ("NGLs") pipelines; we are engaged in crude oil transportation, storage, gathering and marketing; we own and operate natural gas gathering systems; and we own interests in Seaway Crude Pipeline Company ("Seaway"), Centennial Pipeline LLC ("Centennial") and Jonah Gas Gathering Company ("Jonah") and an undivided ownership interest in the Basin Pipeline ("Basin"). Through December 31, 2007, we operated and reported in three business segments:

- transportation, marketing and storage of refined products, 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 NGLs and transportation of NGLs ("Midstream Segment").

Our reportable segments offer different products and services and are managed separately because each requires different business strategies. We operate through TE Products, TCTM and TEPPCO Midstream. Texas Eastern Products Pipeline Company, LLC, a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. We hold a 99.999% limited partner interest in TCTM and 99.999% membership interests in each of TE Products and TEPPCO Midstream. TEPPCO GP holds a 0.001% general partner interest in TCTM and a 0.001% managing member interest in each of TE Products and TEPPCO Midstream. Our interstate transportation operations, including rates charged to customers, are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). In this Report, we refer to refined products, LPGs, petrochemicals, crude oil, lubrication oils and specialty chemicals, NGLs and natural gas, collectively as "*petroleum products*" or "*products*."

Dan L. Duncan and certain of his affiliates, including Enterprise GP Holdings and Dan Duncan LLC, a privately held company controlled by him, control us, our General Partner and Enterprise Products Partners and its affiliates, including Duncan Energy Partners. On May 7, 2007, all of the membership interests in our General Partner, together with 4,400,000 of our Units, were sold by DFI and DFIGP to Enterprise GP Holdings, a publicly traded partnership also controlled indirectly by EPCO. Since that sale, Enterprise GP Holdings owns and controls the 2% general partner interest in us and has the right (through its 100% ownership of our General Partner) to receive the incentive distribution rights associated with the general partner interest. Enterprise GP Holdings, DFI, DFIGP and other entities controlled by Mr. Duncan own 16,691,550, or 17.6%, of our Units.

We do not directly employ any officers or other persons responsible for managing our operations. Under an amended and restated administrative services agreement ("ASA"), EPCO performs all management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us.

At December 31, 2007, 2006 and 2005, we had outstanding 89,911,532, 89,804,829 and 69,963,554 Units, respectively.

Business Strategy

Our business strategy is to grow TEPPCO's sustainable cash flow and to increase cash distributions to our unitholders. The key elements of our strategy are to:

- Focus on internal growth prospects in order to increase pipeline system and terminal throughput, expand and upgrade existing assets and services and construct new pipelines, terminals and facilities;
- Target accretive and complementary acquisitions and expansion opportunities that provide attractive, long-term, balanced growth in each business segment;
- Continue to invest in fee based, demand driven, long-lived growth opportunities that complement our businesses, including blending and logistical opportunities using ethanol;
- Fund our growth with the financial discipline necessary to maintain our investment grade credit ratings; and
- Operate in a safe, efficient, compliant and environmentally responsible manner.

We continue to build a base for long-term growth by pursuing our strategy. Further, we believe the following trends and factors will drive our growth opportunities in 2008 and beyond:

- We expect that refined products imports to the U.S. will increase;
- We expect to see turnover in commercial terminal ownership and operations;
- We expect that Canadian crude oil imports to the U.S. will increase;
- We expect that crude oil imports to the U.S. Gulf Coast will increase;
- We expect the demand for marine transportation services in our market areas to remain strong;
- We expect to see continued expansion opportunities for natural gas gathering and related services in the Jonah, Pinedale and San Juan Basin areas; and
- Standards for use of ethanol and other renewable fuels are currently mandated to increase to 15 billion gallons by 2015 and will ultimately reach 36 billion gallons per year under newly passed energy legislation.

For a detailed discussion of these key trends or factors, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Overview of Business."

Acquisition of Marine Transportation Business

On February 1, 2008, we entered the marine transportation business for refined products, crude oil and lubrication products through the purchase of assets from Cenac Towing Co., Inc., Cenac Offshore, L.L.C. (collectively, "Cenac") and Mr. Arlen B. Cenac, Jr., the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. (collectively, the "Cenac Sellers"), for approximately $443.8 million, consisting of approximately $256.6 million in cash and approximately 4.85 million newly issued Units. Additionally, we assumed $63.2 million of Cenac's long-term debt. We acquired 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements. This business, which we sometimes refer to in this Report as our "marine transportation business," serves refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, as well as the Intracoastal Waterway between Texas and Florida. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast and in the Gulf of Mexico. We financed the cash portion of the acquisition consideration with borrowings under our short-term credit agreement (discussed below). We entered into a transitional operating agreement with the Cenac Sellers under which the purchased assets will continue to be operated by them for up to two years. For additional information, please see "– Marine Transportation Services Segment – Barge Transportation of Petroleum Products."

Chaparral Open Season

In February 2008, our subsidiary, Chaparral Pipeline Company, LLC, ("Chaparral") announced the start of a binding "open season" process to seek shipper support for a proposed expansion of its 845-mile NGL pipeline originating in the Permian Basin of West Texas and eastern New Mexico. The open season is being held to obtain commitments from shippers for a 15-year term at a transportation rate that is sufficient to justify the capital expenditures necessary to expand the Chaparral pipeline capacity. The Chaparral pipeline delivers NGLs to the NGL fractionation complex in Mont Belvieu, Texas. The expansion project is designed to increase annual average system capacity by approximately 15,000 barrels per day or 20,000 barrels per day, depending on shipper response to the open season. The expansion would involve upgrading certain pipe sections, and may include installing additional pumping capability at existing pump stations. If there is sufficient shipper commitment, the additional capacity could be available as soon as early 2009. The open season began February 11, 2008 and continues until March 27, 2008. By April 30, 2008, Chaparral expects to notify shippers who have submitted an executed transportation services agreement whether or not the expansion project will proceed. By signing the transportation services agreement, the shipper will also agree to support Chaparral in any regulatory filings associated with the implementation of the concomitant services.

2007 Developments

Acquisitions

On July 31, 2007, we purchased an active 170,000 barrel LPG storage cavern and associated assets from Duke Energy Ohio, Inc. and Ohio River Valley Propane, LLC for approximately $6.1 million. For additional information, please see "– Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals."

On September 27, 2007, we purchased approximately 44 miles of pipeline in South Texas and related equipment from Shell Pipeline Company LP for approximately $6.8 million. For additional information, please see "– Upstream Segment – Gathering, Transportation, Marketing and Storage of Crude Oil."

Dispositions

On January 23, 2007, we sold a 10-mile, 18-inch diameter segment of pipeline to an affiliate of Enterprise Products Partners for approximately $8.0 million in cash. These assets were part of our Downstream Segment and had a net book value of approximately $2.5 million. The sales proceeds were used to fund construction of a replacement pipeline in the area, in which the new pipeline provides greater operational capability and flexibility. We recognized a gain of approximately $5.5 million on this transaction, which is included in gain on sale of assets in our statements of consolidated income.

On March 1, 2007, TE Products sold its 49.5% ownership interest in Mont Belvieu Storage Partners, L.P. ("MB Storage"), its 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage) and other related assets to Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") for a total of approximately $155.8 million in cash, which includes approximately $18.5 million for other TE Products assets. This sale was in compliance with the October 2006 order and consent agreement with the Bureau of Competition of the Federal Trade Commission ("FTC") and was completed in accordance with the terms and conditions approved by the FTC in February 2007. We used the proceeds from the transaction to partially fund our 2007 portion of the Jonah Phase V expansion (see Midstream Segment below) and other organic growth projects. We recognized gains of approximately $59.6 million and $13.2 million related to the sale of our equity interests and other related assets of TE Products, respectively, which are included in gain on sale of ownership interest in MB Storage and gain on the sale of assets, respectively, in our statements of consolidated income.

In accordance with a transition services agreement between TE Products and Louis Dreyfus, TE Products will provide certain administrative services to MB Storage for a period of up to two years after the sale, for a fee equal to 110% of the direct costs and expenses TE Products and its affiliates incur to provide the services. Payments for these services will be made according to the terms specified in the transition services agreement.

Organic Growth Projects

During 2007, our organic growth projects included the following:

- Construction of a 32-mile, 8-inch diameter pipeline, connecting Valero Energy Corp.'s Texas City refinery to its Houston refinery to deliver feedstock from Texas City to Houston under a 15-year capacity lease.
- Expansion of our LPG pipeline from Greensburg, Pennsylvania, to Philadelphia, Pennsylvania, which increased capacity of the pipeline by approximately 35% in order to participate in market growth.
- Completion of an extension of the refined products pipeline system in Memphis, Tennessee to provide for the delivery of jet fuel to the Memphis airport.
- Commencement of construction on a new refined product terminal located in Boligee, Alabama along the Tennessee-Tombigbee waterway. The 500,000 barrel storage terminal is expected to

have capabilities of receiving U.S. Gulf Coast refined products and distributing them via barge or truck and is expected to be completed in the second quarter of 2008.

- Commencement of construction of the multi-year Motiva project (see "– Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals" below).
- Construction of a mainline connection to both our 20-inch and 16-inch diameter pipelines allowing gasoline and distillate deliveries to a new grass roots terminal serving northeast Arkansas, supported by a 10-year transportation agreement.
- Construction and installation of 50,000 barrel ethanol tank, ethanol truck unloading and gasoline truck rack blending facilities to comply with Missouri's ethanol gasoline mandate. This project is backed by the mandated use of ethanol in historical truck rack demand, charges for leasing space in the new storage tank and additional ethanol handling fees.
- Installation of a new natural gasoline tank with vapor recovery and associated facilities to enable year-round natural gasoline deliveries via new connections to ExxonMobil's refinery and chemical plants.
- Construction of three new crude oil storage tanks at our Cushing, Oklahoma facility, representing a 900,000 barrel, or nearly 50%, increase in our storage capacity at that facility. The expansion, which is supported by long-term lease agreements, brings our total storage capacity at the Cushing facility to 2.8 million barrels.
- Completion of a pipeline connection in our West Texas system to supply crude oil to a New Mexico refinery. This connection is supported by a long-term supply agreement.

Jonah Phase V Expansion

During August 2007, with the completion of the first portion of Jonah's Phase V expansion in which the system gathering capacity was increased to approximately 2.0 Bcf per day, we and Enterprise Products Partners began sharing cash distributions and earnings based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, at December 31, 2007, our ownership interest in Jonah was approximately 80.64%, and Enterprise Products Partners' ownership interest in Jonah was approximately 19.36%. Our ownership interest in Jonah is currently anticipated to remain at 80.64%. The second and final portion of the expansion is expected to be completed during April 2008. For additional information, please see "– Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs."

Debt Financings and Retirements

In May 2007, we issued and sold $300.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due June 1, 2067 ("Junior Subordinated Notes"). We used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under our revolving credit facility and for general partnership purposes. Our payment obligations under the Junior Subordinated Notes are subordinated to all of our current and future senior indebtedness (as defined in the related indenture). TE Products, TEPPCO Midstream, TCTM, and Val Verde Gas Gathering Company, L.P. ("Val Verde") (collectively, the "Subsidiary Guarantors") have jointly and severally guaranteed, on a junior subordinated basis, payment of the principal of, premium, if any, and interest on the Junior Subordinated Notes. For further information, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Financial Condition and Liquidity – Credit Facilities."

In October 2007, we repurchased $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest, and on January 28, 2008, we redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. Additionally, the $180.0 million principal amount of 6.45% TE Products Senior Notes matured and was repaid on January 15, 2008. We funded the retirement of both series with borrowings under a 364-day term credit agreement discussed below. For further information, please see Note 12 in the Notes to Consolidated Financial Statements.

On December 18, 2007, we amended our revolving credit facility, extending the maturity date from December 13, 2011 to December 12, 2012, and allowing us to make unlimited requests for one-year extensions of the maturity date. The amendment also contains an accordion feature whereby the total amount of bank commitments may be increased, with lender approval and the satisfaction of certain other conditions, from $700.0 million to $1.0 billion. For further information, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Financial Condition and Liquidity – Credit Facilities."

On December 21, 2007, we entered into a $1.0 billion unsecured, 364-day term credit agreement to fund the retirement of TE Products' Senior Notes, our marine transportation acquisition and for other general partnership purposes. Loans under the agreement mature on December 19, 2008. For further information, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Financial Condition and Liquidity – Credit Facilities."

Registration Statements

In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 5,000,000 Units in connection with the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (see Note 4 in the Notes to Consolidated Financial Statements), which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. In June 2007, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 Units in connection with the EPCO, Inc. TPP Employee Unit Purchase Plan (see Note 13 in the Notes to Consolidated Financial Statements).

In September 2007, we filed a registration statement with the SEC authorizing the issuance of up to 10,000,000 Units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides owners of our Units a voluntary means by which they can increase the number of Units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional Units. Units purchased through the DRIP may be acquired at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. As of December 31, 2007, 39,796 Units have been issued in connection with the DRIP.

Business Segments

Through December 31, 2007, we operated and reported in three business segments: Downstream Segment, Upstream Segment and Midstream Segment. The following is a discussion of the business and properties of these three historical operating segments. See Note 14 in the Notes to the Consolidated Financial Statements for financial information by segment.

Our marine transportation acquisition resulted in the creation of a new business segment, our Marine Transportation Segment. Accordingly, effective February 1, 2008, we operate and report in four business segments. A discussion of the business and properties of our Marine Transportation Segment follows the discussion of the Midstream Segment below.

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

We conduct business in our Downstream Segment through the following:

- TE Products, our principal operating company for the Downstream Segment;
- TEPPCO Terminals Company, L.P. ("TEPPCO Terminals"), which owns a refined products terminal and two-bay truck loading rack both connected to the mainline system;
- TEPPCO Terminaling and Marketing Company, LLC, ("TTMC") which provides refined products terminaling and marketing services and owns a refined products terminal in Aberdeen, Mississippi;
- a subsidiary which owns the northern portion of the Dean Pipeline ("Dean North"); and
- our 50% equity investment in Centennial.

Properties and Operations

Our Downstream Segment owns, operates or has investments in properties located in 15 states. The operations of the Downstream Segment consist of interstate transportation, storage and terminaling of refined products and LPGs; intrastate transportation of petrochemicals; distribution and marketing operations, including terminaling services and other ancillary services. Other activities are related to the intrastate transportation of petrochemicals under a throughput and deficiency contract.

TE Products is one of the largest pipeline common carriers of refined products and LPGs in the United States. The Downstream Segment, primarily through TE Products, owns and operates an approximately 4,700-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.

As an interstate common carrier, we offer interstate transportation services, pursuant to tariffs filed with the FERC, to any shipper of refined products and LPGs who requests these services, provided that the conditions and specifications contained in the applicable tariff are satisfied. In addition to services for transportation of products, we also provide storage and other related services at key points along our Products Pipeline System. Substantially all of the refined products and LPGs transported and stored in our Products Pipeline System are owned by our customers. The products are received from refineries, connecting pipelines and bulk and marine terminals located principally on the southern end of the pipeline system. The U.S. Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. The products are stored and 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. Based on industry publications and data provided to us by customers, we believe refining capacity and product flow in the U.S. Gulf Coast region will continue to increase in the near term, which we expect will result in increased demand for transportation, storage and distribution facilities in that region. Pipelines are generally the lowest cost method for intermediate and long-haul overland transportation of refined products and LPGs.

The Products Pipeline System includes 35 storage facilities with an aggregate storage capacity of 21 million barrels of refined products and 6 million barrels of LPGs, including leased storage capacity. The Products Pipeline System makes deliveries to customers at 63 locations including 20 truck racks, rail car facilities and marine facilities that we own. Deliveries to other pipelines occur at various facilities owned by TE Products or by third parties.

TE Products owns one active marine receiving terminal at Providence, Rhode Island. This facility includes a 400,000-barrel refrigerated storage tank along with ship unloading and truck loading facilities. We operate the terminal and provide propane loading services to a customer. Our ability in the Downstream Segment to serve propane markets in the Northeast is enhanced by this terminal, which is not physically connected to the Products Pipeline System.

Our Downstream Segment also includes the marketing of refined products through TTMC, which acquired a terminal in November 2006. The facility, located along the Tennessee-Tombigbee Waterway system in Aberdeen, Mississippi, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. We are constructing a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $24.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the second quarter of 2008.

Our Downstream Segment also includes the operations of the northern portion of the Dean Pipeline, which transports refinery grade propylene (“RGP”) from Mont Belvieu, Texas, to Point Comfort, Texas.

The following table lists the material properties and investments of and ownership percentages in our Downstream Segment assets as of December 31, 2007:

	Our Ownership
Refined products and LPGs pipelines and terminals	100%
Mont Belvieu, Texas, to Port Arthur, Texas, petrochemical pipelines	100%
Northern portion of Dean Pipeline	100%
Centennial (1)	50%

(1) Accounted for as an equity investment.

Refined products and LPGs deliveries in MMBbls for the years ended December 31, 2007, 2006 and 2005, were as follows:

	For Year Ended December 31,		
	2007	2006	2005
Refined Products Deliveries: (1)			
Gasoline	96.3	94.9	92.4
Jet Fuels	25.7	25.5	25.4
Distillates (2)	53.0	44.9	42.9
Subtotal	175.0	165.3	160.7
LPGs Deliveries:			
Propane (3)	31.8	36.5	35.6
Butanes (includes isobutane)	10.1	8.5	9.4
Subtotal	41.9	45.0	45.0
Petrochemical Deliveries (4)	43.9	32.5	37.4
Total Product Deliveries	260.8	242.8	243.1
Centennial Product Deliveries	55.6	44.8	50.6

(1) Includes volumes on terminals not connected to the mainline system.

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

(3) Includes short-haul propane barrels of 2.2 million, 10.0 million and 5.4 million for the years ended December 31, 2007, 2006 and 2005, respectively, related to a pipeline that was sold on March 1, 2007 to Louis Dreyfus. The tariff on these pipeline movements was 32.8 cents per barrel.

(4) Includes Dean North RGP volumes and petrochemical volumes on pipelines between Mont Belvieu and Port Arthur, Texas.

Refined Products, LPGs and Petrochemical Pipeline Systems

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, Ohio and our Todhunter facility near Middleton, Ohio. The Products Pipeline System continues eastward from our Todhunter facility 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 our Todhunter facility and ending in Selkirk is an 8-inch diameter line, and the line starting at Greensburg and ending at Marcus Hook varies in diameter from 6 inches to 8 inches. 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 includes a 14-inch diameter line from Seymour to Chicago, Illinois, and a 10-inch diameter line running from Lebanon to Lima, Ohio. This 10-inch diameter pipeline connects to the

Buckeye Pipe Line Company system that serves, among others, markets in Michigan and eastern Ohio. The Products Pipeline System also has a 6-inch diameter pipeline connection to the Greater Cincinnati/Northern Kentucky International Airport.

In addition, the Products Pipeline System contains numerous lines, ranging in size from 6 inches to 20 inches in diameter, associated with the gathering and distribution system, extending from Baytown to Beaumont; Texas City to Baytown; Pasadena, Texas, to Baytown; Mont Belvieu to Beaumont; and an 8-inch diameter pipeline connection to the George Bush Intercontinental Airport terminal in Houston.

The Products Pipeline System also has various diameter lines that extend laterally from El Dorado to Helena, Arkansas, from Shreveport, Louisiana, to El Dorado and from McRae, Arkansas, to Memphis, Tennessee. The line from El Dorado to Helena has a 10-inch diameter. The line from Shreveport to El Dorado varies in diameter from 8 inches to 10 inches. The line from McRae to Memphis has a 12-inch diameter.

TE Products also owns three parallel 12-inch diameter common carrier petrochemical pipelines between Mont Belvieu and Port Arthur. Each of these pipelines is approximately 70 miles in length. The pipelines transport ethylene, propylene, natural gasoline and naphtha. We entered into a 20-year agreement in 2002 with a major petrochemical producer for guaranteed throughput commitments on these three pipelines.

Our Downstream Segment also includes the operations of the northern portion of the Dean Pipeline, which consists of 138 miles of pipeline transporting RGP from Mont Belvieu to Point Comfort.

On July 31, 2007, we purchased an active 170,000 barrel LPG storage cavern, the associated piping and related equipment and a one bay truck rack from Duke Energy Ohio, Inc. and Ohio River Valley Propane, LLC for approximately $6.1 million. These assets are located adjacent to our Todhunter facility near Middleton, Ohio and are connected to our existing LPG pipeline.

In December 2006, we signed an agreement with Motiva Enterprises, LLC (“Motiva”) for us to construct and operate a new refined products storage facility to support the expansion of Motiva’s refinery in Port Arthur, Texas. Under the terms of the agreement, we are constructing a 5.4 million barrel refined products storage facility for gasoline and distillates. The agreement also provides for a 15-year throughput and dedication of volume, which will commence upon completion of the refinery expansion. The project includes the construction of 20 storage tanks, five 5.4-mile product pipelines connecting the storage facility to Motiva’s refinery, 21,000 horsepower of pumping capacity, and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. The storage and pipeline project is expected to be completed by January 1, 2010. As a part of a separate but complementary initiative, we are constructing an 11-mile, 20-inch pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas, which is the primary origination facility for our mainline system. These projects will facilitate connections to additional markets through the Colonial, Explorer and Magtex pipeline systems and provide the Motiva refinery with access to our pipeline system. The total cost of the project is expected to be approximately $310.0 million, which includes $20.0 million for the 11-mile, 20-inch pipeline, $30.0 million of capitalized interest and $17.0 million of scope changes requested by Motiva. Through December 31, 2007, we have spent approximately $47.0 million on this construction project. By providing access to several major outbound refined product pipeline systems, shippers should have enhanced flexibility and new transportation options. Under the terms of the agreement, if Motiva cancels the agreement prior to the commencement date of the project, Motiva will reimburse us the actual reasonable expenses we have incurred after the effective date of the agreement, including both internal and external costs that would be capitalized as a part of the project, plus a ten percent cancellation fee.

Centennial Pipeline Equity Investment

TE Products owns a 50% ownership interest in Centennial and Marathon Petroleum Company LLC (“Marathon”) owns the remaining 50% interest. Centennial, which commenced operations in April 2002, owns an interstate refined products pipeline extending from the upper Texas Gulf Coast to central Illinois. Centennial constructed a 74-mile, 24-inch diameter pipeline connecting TE Products’ facility in Beaumont, Texas, with an existing 720-mile, 26-inch diameter pipeline extending from Longville, Louisiana, to Bourbon, Illinois. The Centennial pipeline intersects TE Products’ existing mainline pipeline near Creal Springs, Illinois, where Centennial constructed a two million barrel refined products storage terminal. Marathon operates the mainline Centennial pipeline, and TE Products operates the Beaumont origination point and the Creal Springs terminal.

Through December 31, 2007, including the amount paid for the acquisition of an additional ownership interest in February 2003, TE Products has invested $118.4 million in Centennial. TE Products has not received any distributions from Centennial since its formation.

Seasonality

The mix of products delivered by our Downstream Segment varies seasonally. We generally realize higher revenues in the Downstream Segment during the first and fourth quarters of each year since LPG volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating, and due to the demand for normal butane, which is used for blending of gasoline. 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. Weather and economic conditions in the geographic areas served by our Products Pipeline System also affect the demand for, and the mix of, the products delivered.

Major Business Sector Markets and Related Factors

Our Products Pipeline System transports refined 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 products are delivered to terminals owned by TE Products, connecting pipelines and customer-owned terminals.

Our Products Pipeline System transports LPGs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States and is the only pipeline that transports LPGs from the upper Texas Gulf Coast to the Northeast. The Products Pipeline System east of our Todhunter facility near Middleton, Ohio, is devoted solely to the transportation of LPGs. Our Products Pipeline System also transports normal butane and isobutane in the Midwest and Northeast for use in the production of motor gasoline.

TTMC conducts distribution and marketing operations whereby we provide terminaling services for our throughput and exchange partners at our Aberdeen terminal. We also purchase refined products from our throughput partners and we in turn establish a margin by selling refined products for physical delivery through spot sales at the Aberdeen truck rack to third-party wholesalers and retailers of refined products. These purchases and sales are generally contracted to occur on the same day.

For further discussion of refined products and LPGs sensitivity to market conditions and other factors that may affect our Downstream Segment, please see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, “– Overview of Business.”

Our major operations in the Downstream Segment consist of the transportation, storage and terminaling of refined products and LPGs along our system. Product deliveries, in MMBbls on a regional basis, for the years ended December 31, 2007, 2006 and 2005, were as follows:

	For Year Ended December 31,		
	2007	2006	2005
Refined Products Deliveries:			
Central (1)	84.3	74.6	73.3
Midwest (2)	66.6	66.6	60.1
Ohio and Kentucky	24.1	24.1	27.3
Subtotal	175.0	165.3	160.7
LPGs Deliveries:			
Central, Midwest and Kentucky (1)(2)	22.1	28.5	26.3
Ohio and Northeast (3)	19.8	16.5	18.7
Subtotal	41.9	45.0	45.0
Petrochemical Deliveries (4)	43.9	32.5	37.4
Total Product Deliveries	260.8	242.8	243.1
Centennial Product Deliveries (5)	55.6	44.8	50.6

(1) Arkansas, Louisiana, Missouri, Mississippi and Texas.

(2) Illinois and Indiana.

(3) New York and Pennsylvania.

(4) Includes Dean North RGP volumes and petrochemical volumes on pipelines between Mont Belvieu and Port Arthur, Texas.

(5) Texas, Louisiana, Mississippi, Tennessee, Kentucky and Illinois.

Customers

Our customers for the transportation of refined products include major integrated oil companies, independent oil companies, the airline industry and wholesalers. End markets for these deliveries are primarily retail service stations, truck stops, railroads, agricultural enterprises, refineries and military and commercial jet fuel users. Propane customers include wholesalers and retailers who, in turn, sell to commercial, industrial, agricultural and residential heating customers, utilities who use propane as a back-up fuel source and petrochemical companies who use propane as a process feedstock. Refineries constitute our major customers for butane and isobutane, which are used as a blend stock for gasolines and as a feed stock for alkylation units, respectively. Our customers for the transportation of petrochemical feedstocks (natural gasoline and naphtha) and semi-finished chemical products (RGP, polymer grade propylene and ethylene) are primarily major chemical companies that consume these components in the production of plastics and a wide array of other commercial products. TTMC's customers include major integrated oil companies and wholesale marketers. Our Downstream Segment depends in large part on the level of demand for refined products and LPGs in the geographic locations that we serve and the ability and willingness of customers having access to the pipeline system to supply this demand.

At December 31, 2007, 2006 and 2005, our Downstream Segment had approximately 130, 125 and 155 customers, respectively. During the years ended December 31, 2007, 2006 and 2005, total revenues attributable to the top 10 customers (and percentage of total segment revenues) were $155.5 million (43%), $143.5 million (47%) and $151.6 million (53%), respectively. During the years ended December 31, 2007 and 2006, no single customer accounted for more than 10% of total Downstream Segment revenues. During the year ended December 31, 2005, Marathon accounted for approximately 14% of total Downstream Segment revenues. During each of the three years ended December 31, 2007, 2006 and 2005, no single customer of the Downstream Segment accounted for 10% or more of TEPPCO's total consolidated revenues.

Competition

The Downstream Segment faces competition from numerous sources. Because pipelines are generally the lowest cost method for intermediate and long-haul overland movement of refined products and LPGs, the Products

Pipeline System's most significant competitors (other than indigenous production in its markets) are pipelines in the areas where the Products Pipeline System delivers products. Competition among common carrier pipelines is based primarily on transportation charges, quality of customer service and proximity to end users. We believe our Downstream Segment is competitive with other pipelines serving the same markets; however, comparison of different pipelines is difficult due to varying product mix and operations.

Trucks, barges and railroads competitively deliver products in some of the areas served by the Products Pipeline System and TTMC. Trucking costs, however, render that mode of transportation less competitive for longer hauls or larger volumes. Pipeline systems inherently compete with barge transportation, especially at those locations that are in close proximity to major waterways. We face competition from rail and pipeline movements of LPGs from Canada and waterborne imports into terminals located along the upper East Coast. TTMC's competition in the area is from refineries that require significant truck transportation to deliver their product in the area TTMC serves. TTMC is able to receive product by barge, which gives it a competitive advantage with respect to other terminaling and marketing businesses in the general area, which generally do not receive product by barge. Further, we view the acquisition of our marine transportation business as a complementary extension of the logistics services that we provide to our existing TTMC customers.

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

We conduct business in our Upstream Segment through the following:

- TCTM, our holding company for the Upstream Segment;
- TEPPCO Crude Pipeline, LLC ("TCPL"), TEPPCO Crude Oil, LLC ("TCO") and Lubrication Services, LLC ("LSI"), wholly owned subsidiaries of TCTM; and
- our 50% equity investment in Seaway.

Properties and Operations

Our Upstream Segment gathers, transports, markets and stores crude oil, and distributes lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Our Upstream Segment uses its asset base to aggregate crude oil and provide transportation and related services to its customers. Our Upstream Segment purchases crude oil from various producers and operators at the wellhead and makes bulk purchases of crude oil on pipelines, terminal facilities and trading locations. The crude oil is purchased under contracts, the majority of which range in term from a thirty-day evergreen to one year. The crude oil is then sold to refiners and other customers. The Upstream Segment transports crude oil through proprietary gathering systems, common carrier pipelines, equity owned pipelines, trucking operations and third party pipelines. The Upstream Segment also exchanges various grades of crude oil and exchanges crude oil at different geographic locations, as appropriate, in order to maximize margins or meet contract delivery requirements. Certain of our crude oil pipeline assets are interstate common carriers, and as such we file tariffs with the FERC. Movement of product on these lines is available to any shipper who requests these services, provided that the conditions and specifications contained in the applicable tariff are satisfied.

The areas served by our gathering and transportation operations are geographically diverse, and the forces that affect the supply of the products gathered and transported vary by region. Crude oil prices and production levels affect the supply of these products. The demand for gathering and transportation is affected by the demand for crude oil by refineries, refinery supply companies and similar customers in the regions served by this business, as well as by production levels in the regions served.

TCO, a significant shipper on TCPL, purchases crude oil and establishes a margin by selling crude oil for physical delivery to third party users. These purchases and sales are generally contracted to occur in the same calendar month. We seek to maintain a balanced marketing position to minimize our exposure to price fluctuations occurring after the initial purchase. However, commodity price risks cannot be completely eliminated.

Crude oil deliveries on our 100% owned pipeline systems, Basin and Seaway and deliveries of lubrication oils and specialty chemicals for the years ended December 31, 2007, 2006 and 2005, were as follows (in millions):

	For Year Ended December 31, 2007	2006	2005
Barrels Delivered:			
Crude oil transportation	96.5	91.5	94.7
Crude oil marketing	232.0	222.1	203.3
Crude oil terminaling	135.0	126.0	110.3
Lubricants and chemicals (total gallons)	15.3	14.4	14.8
Seaway Barrels Delivered:			
Long-haul	49.4	88.4	99.7
Short-haul	229.5	223.4	213.9

Properties

The following table describes the major crude oil pipelines and pipeline systems and the ownership percentages in our Upstream Segment as of December 31, 2007:

Crude Oil Pipeline	Our Ownership	Operator	Description (1)
Red River System	100%	TCPL	1,690 miles of small diameter pipeline; 1,491,000 barrels of storage – North Texas to South Oklahoma
South Texas System	100%	TCPL	1,150 miles of small diameter pipeline; 1,106,000 barrels of storage – South Central Texas to Houston, Texas area
West Texas System	100%	TCPL	360 miles of small diameter pipeline; 415,000 barrels of storage – connecting West Texas and Southeast New Mexico to TCPL's Midland, Texas terminal
Other crude oil assets	100%	TCPL	265 miles of small diameter pipeline; 295,000 barrels of storage – primarily in Texas and Oklahoma
Cushing Terminal	100%	TCPL	17 tanks with 2,668,000 barrels of storage in Cushing, Oklahoma
Midland Station	100%	TCPL	12 tanks with 980,000 barrels of storage in Midland, Texas
Seaway (2)	50% general partnership interest	TCPL	500-mile, 30-inch diameter pipeline – Texas Gulf Coast to Cushing, Oklahoma – 2,600,000 barrels of breakout tankage; 30-mile Texas City system – 1,800,000 barrels of storage tankage and 2,436,000 barrels of breakout tankage (3)
Basin	13% joint ownership	Plains All American Pipeline, L.P.	416-mile pipeline, 20 to 24 inches in diameter – Permian Basin (New Mexico and Texas) to Cushing, Oklahoma

(1) Small diameter of pipeline ranges from two inches to twelve inches.

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

(3) Breakout tankage is used to facilitate transportation and is not leased to customers. Storage tankage is non-FERC jurisdictional and is leased to customers.

Most of the Red River System crude oil is delivered via third party pipelines to Cushing, Oklahoma or to two local refineries. The crude oil on the South Texas System is delivered to Houston area refineries and to Cushing. The West Texas System connects gathering systems to TCPL's Midland, Texas, terminal.

On September 27, 2007, we purchased approximately 44 miles of idle pipeline in South Texas and related equipment from Shell Pipeline Company LP for approximately $6.8 million.

During the third quarter of 2007, three new crude oil storage tanks were placed into service at our Cushing, Oklahoma facility, representing a 900,000 barrel, or nearly 50%, increase in our storage capacity at that facility. The expansion, which is supported by long-term dedicated lease agreements, brings total capacity at the Cushing facility to 2.8 million barrels. In the third quarter of 2007, we completed a pipeline connection in our West Texas system to supply crude oil to a New Mexico refinery. This connection is supported by a long-term supply agreement.

Seaway Crude Pipeline Equity Investment

Seaway is a partnership between TEPPCO Seaway, L.P. ("TEPPCO Seaway"), a subsidiary of TCTM, and subsidiaries of ConocoPhillips. We operate and commercially manage the Seaway assets. Three large diameter lines carry imported crude oil from the Freeport, Texas, marine terminal on the U.S. Gulf Coast to the adjacent Jones Creek Tank Farm, which has six tanks capable of holding approximately 2.6 million barrels of crude oil. The 30-inch diameter, 500-mile pipeline transports crude oil from Freeport to Cushing, a central crude distribution point for the central United States and a delivery point for the New York Mercantile Exchange ("NYMEX"). Additionally, we completed a project in our South Texas system that allows Seaway to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing.

The Seaway crude oil marine terminal facility at Texas City, Texas, supplies refineries in the Houston area. Two pipelines connect the Texas City marine terminal to storage facilities in Texas City and Galena Park, Texas, where there are nine tanks with total capacity of approximately 4.2 million barrels. Seaway is able to provide marine terminaling and crude oil storage services for all Houston area refineries.

The Seaway partnership agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through December 31, 2005, we received 60% of revenue and expense of Seaway. The sharing ratio changed from 60% to 40% on May 12, 2006, and as such, our share of revenue and expense of Seaway was 47% for 2006. Thereafter, we will receive 40% of revenue and expense (and distributions) of Seaway. During the years ended December 31, 2007, 2006 and 2005, we received distributions from Seaway of $12.4 million, $20.5 million and $24.7 million, respectively.

Line Transfers, Pumpovers and Other

Our Upstream Segment provides trade documentation services to its customers, primarily at Cushing and Midland. TCPL documents the transfer of crude oil in its terminal facilities between contracting buyers and sellers. This line transfer documentation service is related to the trading activity by TCPL's customers of NYMEX crude oil contracts and other physical trading activity. This service provides a record of receipts, deliveries and transactions to each customer, including confirmation of trade matches, inventory management and scheduled movements.

The line transfer services also attract physical barrels to TCPL's facilities for final delivery to the ultimate owner. A pumpover occurs when the last title transfer is executed and the physical barrels are delivered out of TCPL's custody. TCPL owns and operates storage facilities primarily in Midland and Cushing with a storage capacity of approximately 3.6 million barrels to facilitate the pumpover business.

LSI distributes lubrication oils and specialty chemicals to natural gas pipelines, gas processors and industrial and commercial accounts. LSI's distribution networks are located in Colorado, Wyoming, Oklahoma, Kansas, New Mexico, Texas and Louisiana.

Customers

Our customers for the sale, transportation and storage of crude oil include major integrated oil companies, independent refiners and marketers. LSI distributes lubrication oils and specialty chemicals to natural gas pipelines, gas processors and industrial and commercial accounts, with networks located in Colorado, Wyoming, Oklahoma, Kansas, New Mexico, Texas and Louisiana.

Gross sales revenue of the Upstream Segment attributable to the top 10 customers (and percentage of total segment gross sales revenue) was $8.1 billion (84%), $7.4 billion (75%) and $5.9 billion (73%) for the years ended December 31, 2007, 2006 and 2005, respectively. For the year ended December 31, 2007, Valero Energy Corp. (“Valero”), BP Oil Supply Company and Shell Trading Company accounted for 17%, 15% and 12%, respectively, of the Upstream Segment gross sales revenue. For the year ended December 31, 2006, Valero and BP Oil Supply Company accounted for 15% and 12%, respectively, of the Upstream Segment gross sales revenue. For the year ended December 31, 2005, Valero accounted for 15% of the Upstream Segment gross sales revenue.

For the year ended December 31, 2007, Valero, BP Oil Supply Company and Shell Trading Company accounted for 16%, 14%, and 12%, respectively, of TEPPCO’s total consolidated revenues. For the year ended December 31, 2006, Valero and BP Oil Supply Company accounted for 14% and 11%, respectively, of TEPPCO’s total consolidated revenues. For the year ended December 31, 2005, Valero accounted for 14% of TEPPCO’s total consolidated revenues.

Competition

The Upstream Segment faces competition from numerous sources. The most significant competitors in pipeline operations in our Upstream Segment are primarily common carrier and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies and other companies in the areas where our pipeline systems receive and 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 can be characterized by thin margins and intense competition for supplies of crude oil at the wellhead.

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

We conduct business in our Midstream Segment through the following:

- TEPPCO Midstream, our holding company for the Midstream Segment;
- our 80.64% equity investment in Jonah Gas Gathering Company, which gathers natural gas;
- Val Verde Gas Gathering Company, L.P., which gathers and treats natural gas for carbon dioxide removal;
- Chaparral Pipeline Company, LLC and Quanah Pipeline Company, LLC (collectively referred to as “Chaparral” or “Chaparral NGL system”), Panola Pipeline Company, LLC (“Panola Pipeline”), Dean Pipeline Company, LLC (“Dean Pipeline”) and Wilcox Pipeline Company, LLC (“Wilcox Pipeline”), which transport NGLs; and
- TEPPCO Colorado, LLC (“TEPPCO Colorado”), which fractionates NGLs.

Properties and Operations

Our Midstream Segment gathers natural gas, transports NGLs and fractionates NGLs. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances and the purchase and sale of natural gas by Jonah to facilitate system operations and to provide a service to some of the producers on the system.

Volume information for the years ended December 31, 2007, 2006 and 2005, is presented below:

	For Year Ended December 31,		
	2007	2006	2005
Gathering – Natural Gas – Jonah (Bcf) (1)	587.4	473.9	415.2
Gathering – Natural Gas – Val Verde (Bcf)	175.7	181.9	180.7
Transportation – NGLs (MMBbls)	77.0	69.7	61.1
Fractionation – NGLs (MMBbls)	4.2	4.4	4.4

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise Products Partners, Jonah was deconsolidated and operating results after August 1, 2006, are included in equity earnings. However, the table includes Jonah's gathering volumes for the full years ended December 31, 2007, 2006 and 2005.

Jonah Gas Gathering Joint Venture

We entered the natural gas gathering business in late 2001 with our acquisition of the Jonah system in the Green River Basin in southwestern Wyoming. The majority of the growth in the Midstream Segment is due to our expansions of the Jonah system. Since the acquisition of Jonah in 2001, we have expanded the system in four phases, increasing system capacity from approximately 450 MMcf/d to approximately 1.5 Bcf per day, adding 130 miles of pipeline and 36,700 horsepower of compression at an aggregate cost of approximately $242.7 million. We are currently in the fifth phase of expanding the Jonah system.

On August 1, 2006, Enterprise Products Partners, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the partnership through which we have owned our interest in the Jonah system. Previously, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective with the formation of the joint venture on August 1, 2006, Jonah was deconsolidated, and we began using the equity method of accounting to account for our investment in Jonah.

Enterprise Products Partners serves as operator of Jonah. The Jonah joint venture is governed by a management committee comprised of two representatives approved by Enterprise Products Partners and two representatives approved by us, each with equal voting power. The formation of the joint venture was reviewed and recommended for approval by the Audit, Conflicts and Governance Committee of the Board of Directors of our General Partner ("ACG Committee").

In February 2006, Enterprise Products Partners assumed the management of the Jonah Phase V expansion project and funded the initial costs of the expansion. Beginning with the August 1, 2006 formation of the Jonah joint venture, we reimbursed Enterprise Products Partners for 50% of the expansion costs it had previously advanced, and we and Enterprise Products Partners began sharing the costs of the expansion equally.

In connection with the joint venture arrangement, we and Enterprise Products Partners are continuing the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 Bcf per day to approximately 2.35 Bcf per day and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which included a pipeline loop of 75 miles of 36-inch diameter pipe and 12 miles of 24-inch diameter pipe that was completed in December 2006, increased the system gathering capacity to approximately 2.0 Bcf per day and was completed in July 2007. The second and final portion of the expansion, expected to be completed during April 2008, will add approximately 102,000 horsepower of compression and is expected to increase the system gathering capacity to approximately 2.35 Bcf per day. The total anticipated cost of the Phase V expansion is expected to be approximately $505.0 million.

From August 1, 2006 through July 2007, we and Enterprise Products Partners equally shared the costs of the Phase V expansion, and beginning in December 2006 with the completion of a portion of the expansion (discussed above), Enterprise Products Partners began sharing in the incremental cash flow and distributions resulting from the operation of those new facilities. During August 2007, with the completion of the first portion of the expansion, we and Enterprise Products Partners began sharing joint venture cash distributions and earnings based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, at December 31, 2007, our ownership interest in Jonah was approximately 80.64%, and Enterprise Products Partners' ownership interest in Jonah was approximately 19.36%. To the extent the Phase V expansion costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise Products Partners will each pay our respective ownership share (approximately 80% and 20%, respectively). Our ownership interest in Jonah is currently anticipated to remain at 80.64%. During the year ended December 31, 2006, Jonah declared a distribution to us of $41.6 million, of which $30.0 million was paid in cash and the remainder was reflected as a receivable from Jonah. During the year ended December 31, 2007, we received distributions from Jonah of $100.0 million, which included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007.

Jonah Gas Gathering System Business. The Jonah system serves the Jonah and Pinedale fields in Wyoming, which, according to the Energy Information Administration's 2006 estimates, were among the top ten natural gas producing fields in the United States. The system delivers natural gas to pipelines and gas processing facilities owned by others. From the processing facilities, the natural gas is delivered into several interstate pipeline systems located in the region for transportation to end-use markets throughout the Midwest, the West Coast and the Rocky Mountain regions. Interstate pipelines in the region include Kern River, Northwest, Colorado Interstate Gas and Questar. Upon the expected completion of the Phase V expansion in April 2008, the Jonah system will consist of approximately 643 miles of pipelines ranging in size from three inches to 36 inches in diameter, five compressor stations with an aggregate of approximately 261,500 horsepower and related metering facilities. Gas gathered on the Jonah system is collected from approximately 1,476 producing wells in southwestern Wyoming's Green River Basin.

In addition to gathering natural gas, Jonah also purchases gas at the wellhead and sells gas and condensate. The Jonah system sells condensate liquid from the natural gas stream to TCO. The sales price is contractually based on a crude oil index price less a differential. In May 2006, we began to purchase gas at the wellhead on Jonah and re-sell the aggregated quantities at key Jonah delivery points in order to facilitate Jonah's operations. The purchases and sales generally occur within the same month to minimize price risk.

Jonah has fee based gathering agreements with fees that increase as field pressures decrease. Approximately 18 producers are connected to the system, of which seven have life-of-lease contracts that represented approximately 96% of the volumes of the system in 2007. Under these agreements, Jonah gathers and compresses the natural gas supplied to its gathering system and then redelivers the natural gas to gas processing facilities and interstate pipelines located in the region for a fixed fee. Jonah does not generally take title to the natural gas gathered with the exception of inventory imbalances and the purchase and sale of natural gas to facilitate system operations and to provide a service to some of the producers on the system. Other than the effects of normal operating pressure fluctuations, we can neither influence nor control the operation, development or production levels of the gas fields served by the Jonah system, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

Val Verde Gas Gathering System

The Val Verde system, which we have owned since 2002 and operated since mid-2005, consists of approximately 400 miles of pipeline ranging in size from four inches to 36 inches in diameter, 14 compressor stations operating over 75,000 horsepower of compression and a large amine treating facility for the removal of carbon dioxide. The gathering system is capable of gathering approximately one billion cubic feet of gas per day, and the current treating capacity of the Val Verde plant is approximately 550 million cubic feet of gas per day. Treating capacity is affected by the content of carbon dioxide in the gas stream and is more indicative of actual system capacity than the overall gathering capacity of the system. The Val Verde system delivers gas to two interstate pipeline systems serving the western United States, as well as local New Mexico markets.

The Val Verde system gathers coal bed methane ("CBM"), convention natural gas and commingled natural gas from the Fruitland Coal Formation of the San Juan Basin in New Mexico and Colorado. The system gathers natural gas from more than 500 separate wells throughout northern New Mexico and southern Colorado. Gathering and treating services are provided pursuant to long-term fixed-fee contracts with approximately 40 natural gas producers in the San Juan Basin. These contracts are generally long-term commitments, with evergreen clauses, the majority of which escalate annually. Under these contracts, Val Verde gathers the natural gas supplied to its gathering systems, removes carbon dioxide to meet pipeline specifications and redelivers the natural gas for a fixed fee. Val Verde does not take title to the natural gas. CBM volumes gathered on the Val Verde system have begun to decline, primarily due to the natural decline of CBM production and the maturity of the field. Other than the effects of normal operating pressure fluctuations, we can neither influence nor control the operation, development or production levels of the gas fields served by the Val Verde system, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

In December 2004, we completed a 16-mile project to connect Val Verde with a third party gathering system originating in Colorado and entered into a seven year agreement to transport and treat natural gas through this connection. Val Verde transported an average of 138 MMcf/d from this interconnection in 2007.

NGL Transportation and Fractionation

The NGL pipelines of the Midstream Segment are located along the Texas Gulf Coast, in East Texas and from southeastern New Mexico and West Texas to Mont Belvieu. They are all wholly owned and operated by our subsidiaries. Information about these NGL pipelines as of December 31, 2007, is set forth in the following table:

NGL Pipeline	Physical Capacity (barrels/day)	Description
Chaparral (1) (2)	135,000	845 miles of pipeline – West Texas and New Mexico to Mont Belvieu, Texas
Quanah (1)	30,000	180 miles of pipeline – Sutton County, Texas to the Chaparral Pipeline near Midland, Texas
Panola (3)	70,000	189 miles of pipeline – Carthage, Texas to Mont Belvieu, Texas
San Jacinto (3)	12,000	34 miles of pipeline – Carthage, Texas to Longview, Texas
The southern portion of the Dean Pipeline (4)	8,500	155 miles of pipeline – South Texas to Point Comfort, Texas

(1) The Chaparral NGL system, including the Quanah Pipeline, extends from West Texas and New Mexico to Mont Belvieu. Shippers on Chaparral, which include Enterprise Products Partners (see “Customers” below), pay posted tariffs, which tariffs are adjusted each July based upon a FERC approved indexing methodology. The specified capacity of the Chaparral Pipeline represents aggregate volume transported system-wide. Long-haul capacity from West Texas and New Mexico to Mont Belvieu is approximately 115,000 barrels per day.

(2) See discussion in “Chaparral Open Season” within these Items 1 and 2.

(3) The Panola Pipeline and San Jacinto Pipeline originate at an East Texas Plant Complex in Panola County, Texas, and transport NGLs for major integrated oil and gas companies, including Enterprise Products Partners (see “Customers” below).

(4) The southern portion of the Dean Pipeline originates in South Texas and transports NGLs for one customer and delivers those NGLs into that customer’s pipeline at Point Comfort, Texas.

TEPPCO Colorado has two NGL fractionation facilities which separate NGLs into individual components. TEPPCO Colorado is currently supported by a fractionation agreement with DCP Midstream Partners, L.P. (formerly Duke Energy Field Services, LLC) (“DCP”) through 2018, under which TEPPCO Colorado receives a variable fee, primarily a front-loaded fee determined by cumulative volumes fractionated during the contract year and delivered to DCP. Under an operation and maintenance agreement, DCP also operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DCP a set volumetric rate for all fractionated volumes delivered to DCP.

Seasonality

At Jonah, new well connections are subject to seasonal constraints as a result of winter range restrictions in the Pinedale field. Producers in the Pinedale field are prohibited from drilling activities typically during November through April due to wildlife restrictions, and we are accordingly limited in our ability to connect new wells to the system during that time.

Customers

The Midstream Segment's customers for natural gas gathering include major integrated oil and gas companies and large to medium-sized independent producers. Natural gas from Jonah and Val Verde is delivered into major interstate gas pipelines for delivery primarily to markets in the western and mid-continent areas of the United States. The Midstream Segment's customers for transporting NGLs include affiliates of EPCO and other major integrated oil and gas companies.

At December 31, 2007, the Midstream Segment had approximately 52 customers. Revenue attributable to the top 10 customers (and percentage of total segment revenues) was $105.8 million (87%) for the year ended December 31, 2007, of which ConocoPhillips (and its subsidiary, Burlington Resources Inc.), DCP and its affiliates, and Enterprise Products Partners and its affiliates accounted for approximately 22%, 20% and 11%, respectively. At December 31, 2006, the Midstream Segment had approximately 65 customers. Revenue attributable to the top 10 customers (and percentage of total segment revenues) was $163.4 million (79%) for the year ended December 31, 2006, of which EnCana Corporation, ConocoPhillips (and its subsidiary, Burlington Resources Inc.), DCP and its affiliates and BP Energy accounted for approximately 15%, 14%, 12% and 12%, respectively. At December 31, 2005, the Midstream Segment had approximately 70 customers. Revenue attributable to the top 10 customers (and percentage of total segment revenues) was $194.7 million (87%) for the year ended December 31, 2005, of which EnCana Corporation, DCP and its affiliates and ConocoPhillips (and its subsidiary, Burlington Resources Inc.) accounted for approximately 20%, 19% and 15%, respectively. During each of the three years ended December 31, 2007, 2006 and 2005, no single customer of the Midstream Segment accounted for 10% or more of TEPPCO's total consolidated revenues.

Competition

Competition in the natural gas gathering operations of our Midstream Segment is based largely on reputation, efficiency, system reliability, system capacity and price 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 our Midstream Segment, and those producers could also elect to construct proprietary gas gathering systems. Success in the gas gathering and treating business segment is based primarily on a thorough understanding of the needs of the producers served, a strong commitment to providing responsive, high-quality customer service, as well as proximity to new drilling and development.

The Midstream Segment's NGL pipeline operations face competition from other competing pipelines. The most significant competition for the NGL pipeline operations of our Midstream Segment comes from pipelines owned and operated by major oil and gas companies and other large independent pipeline companies with facilities that are in or near our operational areas. The ability to compete in the NGL pipeline area is based primarily on competitive fees, the quality of customer service and knowledge of products and markets.

Marine Transportation Segment – Barge Transportation of Petroleum Products

We conduct business in our Marine Transportation Segment through TEPPCO Marine Services, LLC ("TEPPCO Marine"), which transports refined products, crude oil, condensate and NGLs via tugboats, push boats and barges primarily on the United States inland waterway system and between domestic ports along the Gulf of Mexico Intracoastal Waterway and performs well-testing service activities and crude oil gathering for offshore production facilities and pipelines. We entered the marine transportation business on February 1, 2008 when we acquired 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements from the Cenac Sellers for approximately $443.8 million, consisting of approximately $256.6 million in cash and approximately 4.85 million newly issued Units. Additionally, we assumed $63.2 million of Cenac's long-term debt.

Concurrent with the acquisition, we entered into a transitional operating agreement providing for the sellers' operation of the acquired business for a period of up to two years from the date of acquisition.

Properties and Operations

The United States inland waterway system is a vast and extensively utilized transportation system, consisting of a network of interconnected rivers and canals that serve as water highways upon which vast quantities of products are transported annually. The inland waterway system includes approximately 12,000 miles of waterways that are generally considered navigable.

The marine transportation industry uses push boats and tugboats as power sources and barges for freight capacity. The combination of the power source and barge freight capacity is called a tow. Our inland tows generally consist of one push boat and from one to four barges, depending upon the horsepower of the push boat, the trading territory, waterway conditions, customer requirements and prudent operations. Our offshore tows generally consist of one tugboat and one ocean-certified tank barge.

The following is a summary description of the marine vessels we use in our marine transportation business:

Class of Equipment	Number in Class	Capacity (bbl)/ Horsepower (hp)
Inland:		
Barges	16	< 25,000 bbl
Barges	65	> 25,000 bbl
Push boats	18	< 2,000 hp
Push boats	17	> 2,000 hp
Offshore:		
Barges	8	> 20,000 bbl
Tug boats	4	< 2,000 hp
Tug boats	3	> 2,000 hp

The commercial and other agreements constituting part of the marine transportation business require consents of third parties to assign the agreements to TEPPCO Marine, which TEPPCO Marine and Cenac began seeking promptly after the closing of the acquisition. Under the purchase agreement, TEPPCO Marine is entitled to Cenac's economic benefit of these unassigned agreements, and Cenac continues to be obligated to use reasonable efforts to obtain those consents.

Most of our marine transportation revenue is expected to be derived from term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from designated origins to designated destinations at set day rates. Most of the term contracts we are acquiring from Cenac have one-year terms with the remainder having terms of up to two years. All of the existing contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. We do not assume ownership of the products we transport in this segment. As is typical for inland liquid affreightment contracts, the term contracts we are acquiring establish firm day rates but do not include revenue or volume guarantees. Most of the contracts include escalation provisions to recover specific increased operating costs such as incremental increases in labor and equipment retrofits required by emerging government regulation. The costs of fuel and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts.

Our marine transportation business is subject to regulation by the U.S. Department of Transportation, Department of Homeland Security, Commerce Department and the U.S. Coast Guard ("USCG") and federal and state laws. Substantially all of our inland barges are inspected by the USCG and carry certificates of inspection. Our inland and offshore towing vessels are not currently subject to USCG inspection requirements; however, regulations are currently proposed that would subject inland and offshore towing vessels to USCG inspection requirements. Most of our offshore towing vessels and barges are built in compliance with American Bureau of Shipping ("ABS") Load Line standards and are inspected periodically by ABS to maintain this standard. The crews employed by Cenac aboard vessels, including captains, pilots, engineers, tankermen, deckhands and ordinary seamen, are all licensed by the USCG with the exception of engineers and deckhands on inland vessels. We or Cenac, as operator, are required by various governmental agencies to obtain licenses, certificates and permits for our vessels depending upon such factors as the cargo transported, the waters in which the vessels operate and other factors.

Cenac belongs to the American Waterways Operators (“AWO”) Responsible Carrier Program (“RCP”). The program provides a framework of safety standards and best practices designed to continuously enhance member companies’ safety and efficiency in the operation of inland marine vessels. The program complements and builds upon existing government regulations, requiring company safety and training standards that in many instances exceed those required by federal law or regulation. Many of Cenac’s contracts contain provisions regarding AWO membership and RCP compliance. The Responsible Carriers Program has been recognized by many groups, including the USCG and shipper organizations. Cenac is periodically audited by an AWO-certified auditor to verify compliance.

We are a named insured with respect to our marine transportation assets on the policies of Cenac for an interim period, and are obligated under the transitional operating agreement to replace this coverage with a comparable program by June 30, 2008. Limited hull coverage is provided by the existing Cenac insurance policies.

Vessel Management, Crewing and Employees

In connection with our entry in the marine transportation business, we entered into a transitional operating agreement with Cenac for a period of up two years from the date of acquisition under which the sellers will operate our Marine Transportation Segment with their marine and shore-based support employees. Cenac maintains an experienced work force of marine and shore-based personnel. As of February 15, 2008, approximately 355 of Cenac’s employees provided services to TEPPCO Marine under the transitional operating agreement. Cenac’s tow and barge captains are non-union management supervisors. Its marine employees are paid on a daily basis, and the majority work 14 days on and 7 days off. Cenac’s shore-based personnel are generally salaried and most are located at its headquarters in Houma, Louisiana. We reimburse Cenac for the salaries and other benefits of the employees providing services to us under the transitional operating agreement.

Cenac’s shore staff provides support for all aspects of our fleet and business operations, including sales and scheduling, crewing and human resources functions, engineering, compliance and technical management, financial and insurance services, and information technology. A staff of dispatchers and schedulers maintain a 24-hour duty rotation to monitor communications and to coordinate fleet operations with our customers and terminals. Communication with our vessels is accomplished by various methods, including wireless data links, cellular telephone, VHF and radio and satellite telephone.

Under the transitional operating agreement, Cenac is responsible for maintaining our vessels in seaworthy and good working condition and operating our vessels in accordance with applicable laws and prudent industry practices. Cenac’s trained crews regularly inspect each vessel, both at sea and in port, and perform all routine preventive maintenance. Shore-based staff conduct quarterly inspections regarding overall condition, maintenance, safety and crew welfare, and selected vessels are inspected annually by third party consultants.

Seasonality

We expect that overall increased demand for refined products such as motor fuels during the spring and summer driving seasons will result in increased demand for our marine transportation services during those seasons.

Customers

Our largest marine transportation customers include major and independent oil companies, crude oil producers, traders and refiners. We provide towing services primarily for major oil companies in the refining industry in the states along the Gulf coast.

Competition

We expect that our marine transportation business will compete with inland marine transportation companies as well as providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. While competition within the marine transportation business is based largely on price, we believe that the decline in the past two decades in the number of inland barges operating in the inland U.S. waterways, consolidation in the marine transportation industry and barriers to entry in the industry, such as cost and ability to obtain licensed and qualified personnel, have resulted in a favorable pricing environment for our marine transportation business. We also believe that our ability to offer alternative means of transportation, for example, via our Products Pipeline System, will position us well to compete against pipelines and marine transportation companies that service the areas in which our marine transportation business operates. We believe we can offer a competitive advantage over rail tank cars and tractor-trailer tank trucks because, by volume, marine transportation is a substantially more efficient, and generally less expensive, mode of transporting petroleum products and by-products. For example, one of our typical two inland barge unit tows carry a volume of product equal to approximately 69 rail cars or 278 tanker trucks.

Title to Properties

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

Capital Expenditures

Capital expenditures, excluding acquisitions and contributions to joint ventures, totaled $228.2 million for the year ended December 31, 2007. Revenue generating projects include those projects which expand service into new markets or expand capacity into current markets. Capital expenditures to sustain existing operations include projects required by regulatory agencies or required life-cycle replacements. System upgrade projects improve operational efficiencies or reduce cost. We capitalize interest costs incurred during the period that construction is in progress. The following table identifies capital expenditures by segment for the year ended December 31, 2007 (in millions):

	Revenue Generating	Sustaining Existing Operations	System Upgrades	Capitalized Interest	Total
Downstream Segment	$ 125.9	$ 27.5	$ 6.8	$ 5.2	$ 165.4
Midstream Segment	2.3	4.5	0.6	—	7.4
Upstream Segment	32.9	19.1	0.7	1.7	54.4
Other	—	1.0	—	—	1.0
Total	$ 161.1	$ 52.1	$ 8.1	$ 6.9	$ 228.2

Revenue generating capital spending by the Downstream Segment totaled $125.9 million and was used primarily for the construction of a new refined products storage facility to support the expansion of Motiva's refinery in Port Arthur, Texas, construction of a new terminal in Boligee, Alabama, the continued integration of assets from an acquisition in 2005 and expansion of delivery capability into Memphis, Tennessee. Revenue generating capital spending by the Midstream Segment totaled $2.3 million and was used primarily to increase capacity of the Panola Pipeline. Revenue generating capital spending by the Upstream Segment totaled $32.9 million and was used primarily for the expansion of our facilities and pipeline connections in West Texas and Cushing, Oklahoma. In order to sustain existing operations, we spent $27.5 million for various Downstream Segment pipeline projects, $4.5 million for the Midstream Segment and $19.1 million for Upstream Segment facilities. An additional $8.1 million was spent on system upgrade projects among all of our business segments.

We estimate that capital expenditures, excluding acquisitions and joint venture contributions, for 2008 will be approximately $403.0 million (including $13.0 million of capitalized interest). We expect to spend approximately $321.0 million for revenue generating projects, which includes $153.0 million for our expected spending on the Motiva project. We expect to spend approximately $57.0 million to sustain existing operations (including $17.0 million for pipeline integrity) including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $12.0 million to improve operational efficiencies and reduce costs among all of our business segments. Additionally, we expect to invest approximately $124.0 million (including $3.0 million of capitalized interest) in our Jonah joint venture during 2008 for the completion of the Phase V expansion and additional facilities to expand the Pinedale field production.

During 2008, TE Products may be required to contribute cash to Centennial to cover capital expenditures, debt service requirements or other operating needs. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

Regulation

FERC

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

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

On October 24, 1992, Congress passed the Energy Policy Act. The Energy Policy Act deemed just and reasonable under the ICA (*i.e*., “grandfathered”) liquids pipeline rates that were in effect for the twelve months preceding enactment and that had not been subject to complaint, protest or investigation. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show that it was previously contractually barred from challenging the rates, or that the economic circumstances of the liquids pipeline that were a basis for the rate or the nature of the service underlying the rate had substantially changed or that the rate is unduly discriminatory or preferential. Some but not all of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. There is currently pending before the U.S. Court of Appeals for the D.C. Circuit (“D.C. Circuit”) a challenge to the FERC’s standards for assessing when such a substantial change has occurred. We cannot at this time predict what effect, if any, the decision in that case will have on the ability of parties to challenge grandfathered rates.

Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year to year in the Producer Price Index for finished goods (“PPI”). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline’s costs. Effective March 21, 2006, FERC issued its final order concluding its second five-year review of the oil pipeline pricing index. FERC concluded that for the five-year period commencing July 1, 2006, liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 1.3 percent (“PPI Index”). At the end of that five year period, in July 2011, the FERC will once again review the PPI Index to determine whether it continues to measure adequately the cost changes in the oil pipeline industry.

As an alternative to using the PPI Index, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings (“Market-Based Rates”) or agreements with all of the pipeline’s shippers that the rate is acceptable. TE Products has been granted permission by the FERC to utilize Market-Based Rates for all of its refined products movements other than the Little Rock, Arkansas, Arcadia and Shreveport-Arcadia, Louisiana destination markets, which are currently subject to the PPI Index. As with all rates for service on an oil pipeline subject to FERC regulation under the ICA, TE Products must file its market-based rates with FERC and charge those rates on a non-discriminatory basis, such that the same Market-Based Rate shall be charged to similarly situated shippers. With respect to LPG movements, TE Products uses the PPI Index. All interstate transportation movements of crude oil by TCPL are subject to the PPI Index as are the NGL interstate transportation movements on the Chaparral NGL system.

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

In that regard, one element of the FERC’s cost-of-service methodology as it affects partnerships such as us remains under review. In a case involving Lakehead Pipe Line Company, L.P., a partnership that operates a crude oil pipeline, the FERC concluded in its Opinion No. 397 that Lakehead was entitled to include in calculating its rates an income tax allowance only with respect to the portion of its earnings that are attributable to its partners that are not individuals, rationalizing that income attributable to individuals would be subject to only one level of taxation. The parties subsequently settled the case, so there was no judicial review of the FERC’s decision. The FERC subsequently applied this approach in proceedings involving SFPP, L.P., which is a subsidiary of a publicly traded limited partnership engaged in the transportation of petroleum products. In the first SFPP proceeding, Opinion No. 435, the FERC (among other things) affirmed Opinion No. 397’s determination that there should not be an income tax allowance built into a petroleum pipeline’s rates for income attributable to non-corporate partners.

Following several FERC orders on rehearing, the matter was appealed to the D.C. Circuit. The court found the Lakehead policy to lack a reasonable basis and vacated the portion of the FERC’s rulings that permitted SFPP an income tax allowance in accordance with that policy. The court remanded the issue to the FERC for further consideration, and the FERC thereafter initiated a broader inquiry into the implications of the court’s decision on other FERC-regulated companies. That was followed by the issuance of the FERC’s “Policy Statement on Income Tax Allowances” (“Policy Statement”) on May 4, 2005, which addressed the circumstances in which a partnership or other pass-through entity would be permitted to include a tax allowance in its cost of service. On December 16, 2005, the FERC issued its “Order on Initial Decision and on Certain Remanded Cost Issues” in various dockets involving SFPP (the “SFPP Order”). Among other things, the SFPP Order applied the Policy Statement to the specific facts of the SFPP case, suggesting how the FERC will treat other Master Limited Partnership (“MLP”) petroleum pipelines. The SFPP Order confirmed that an MLP is entitled to a tax allowance with respect to partnership income for which there is an “actual or potential income tax liability” and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate.

Both the SFPP Order and the Policy Statement were appealed to the D.C. Circuit, in a case that was argued before the court on December 12, 2006. The matter is currently awaiting a decision.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that affect the rates we charge and terms and conditions of that service. Although state regulation typically is less onerous than FERC regulation, proposed and existing rates subject to state regulation and the provision of non-discriminatory service are subject to challenge by complaint.

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

Environmental and Safety Matters

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

The following is a discussion of all material environmental and safety laws and regulations that relate to our operations. We believe that we are in material compliance with all these environmental and safety laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial position. We cannot ensure, however, that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act (“CWA”), and comparable 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. The Environmental Protection Agency (“EPA”) has adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate. These permits may require us to monitor and sample the storm water run-off. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our operations.

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 United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety (“OPS”) or the EPA, as appropriate. 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. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

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

Air Emissions

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

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

The U.S. Congress is actively considering legislation to reduce emissions of “greenhouse gases,” including carbon dioxide and methane. In addition, at least 14 states have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation addressing emissions of greenhouse gases. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that restrict emissions of greenhouse gases could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our operations or financial condition.

Risk Management Plans

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

Solid Waste

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

Environmental Remediation

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

At December 31, 2007, we have an accrued liability of $4.0 million related to sites requiring environmental remediation activities. A discussion of legal proceedings that relate to environmental remediation is included elsewhere in this Report under the caption Item 3. Legal Proceedings.

Maritime Law

The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under the General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues.

Jones Act

The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. As a result of the marine transportation business acquisition on February 1, 2008, we now engage in maritime transportation between locations in the United States, and as such, we are subject to the provisions of the law. As a result, we are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flag vessels be manned by United States citizens. Foreign-flag seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flag vessel operations compared to foreign-flag vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flag vessel owners. The United States Coast Guard and American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flag operators than for owners of vessels registered under foreign flags of convenience. Following Hurricane Katrina, and again after Hurricane Rita, emergency suspensions of the Jones Act were effectuated by the United States government. The last suspension ended on October 24, 2005. Future suspensions of the Jones Act or other similar actions could adversely affect our cash flow and ability to make distributions to our unitholders. The Jones Act also provides a remedy in damages for crew members injured in the course and scope of their employment. In certain circumstances, a Jones Act seaman can have dual employers under the borrowed servant doctrine.

Merchant Marine Act of 1936

The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the president of the United States of a national emergency or a threat to the national security, the United States secretary of transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our towboats or barges were purchased or requisitioned by the United States government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our towboats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our towboats or barges.

DOT Pipeline Compliance Matters

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

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

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

Safety Matters

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

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request. We are subject to OSHA Process Safety Management (“PSM”) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA regulations.

Employees

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the ASA or by other service providers. For additional information regarding the ASA, please see "Relationship with EPCO" under Item 13 of this Annual Report. As of December 31, 2007, there were approximately 2,300 EPCO personnel that spend all or a portion of their time engaged in our business. Approximately 1,000 of these individuals devote all of their time performing management and operating duties for us. We reimburse EPCO for 100% of the costs it incurs to employee these individuals. The remaining approximate 1,300 personnel are part of EPCO's shared service organization and spend all or a portion of their time engaged in our business. The cost for their services is reimbursed to EPCO under the ASA and is generally based on the percentage of time such employees perform services on our behalf during the year. For additional information regarding our relationship with EPCO, please read Item 13 of this Report.

Available Information

As a large accelerated filer, we electronically file certain documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time to time, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site (http://www.sec.gov) that contains reports and other information regarding issuers that file electronically with the SEC, including us.

We provide electronic access to our periodic and current reports on our Internet website (http://www.teppco.com). These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our Investor Relations Department at (800) 659-0059 for paper copies of these reports free of charge.

Item 1A. *Risk Factors*

There are many factors that may affect us and our joint ventures. Security holders and potential investors in our securities should carefully consider the risk factors set forth below, as well as the discussion of other factors that could affect us or our joint ventures included elsewhere in this Report, including under the captions "Cautionary Note Regarding Forward-Looking Statements," "Items 1 and 2. Business and Properties," "Item 3. Legal Proceedings," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and "Item 13. Certain Relationships and Related Transactions, and Director Independence." If one or more of these risks were to materialize, our business, financial position or results of operations could be materially and adversely affected. We are identifying these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

Risks Relating to Our Business

Potential future acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

As part of our business strategy, we continually evaluate and acquire assets and businesses and undertake expansions that we believe complement our existing assets and businesses. Acquisitions and expansions may require substantial capital or the incurrence of substantial indebtedness. Consummation of future acquisitions and expansions may significantly change our capitalization and results of operations. Our growth may be limited if acquisitions or expansions are not made on economically favorable terms.

Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets, personnel and the businesses associated with them and new geographic areas and the diversion of management’s attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities associated with the acquired business for which we may have no recourse or limited recourse under applicable indemnification provisions.

Our marine transportation acquisition may not achieve anticipated results.

We do not have a depth of experience in the marine transportation business and will initially depend on Cenac and its personnel to continue to operate the marine vessels we acquired for up to two years under a transitional operating agreement entered into in connection with the acquisition. The success of this business is largely dependent on maintaining adequate, licensed crew for our towboats. If the services of Cenac key personnel become limited or unavailable, or if Cenac fails to operate the vessels at the levels we expect, we may lose customers, experience delays or problems with maintaining the vessels or their cargo or other resultant material adverse effects on our business, financial condition and results of operations. Further, we may not be able to locate or engage qualified replacement personnel on acceptable terms and can give no assurance that we will be able to adequately staff our vessels upon expiration or termination of the transitional operating agreement. Recently, high United States employment, coupled with Hurricanes Katrina and Rita that displaced labor and created reconstruction job opportunities in the oil service and construction industries along the Gulf Coast, made for a tight Gulf Coast labor market, resulting in personnel shortages in the marine transportation industry.

Integrating the operations of our marine transportation acquisition with our other operations will present challenges to our management, including:

- managing relationships with customers in a new line of business;
- potential loss of key employees, customers or suppliers;
- assessing the internal controls and procedures for the acquired operations that we are required to maintain under the Sarbanes-Oxley Act of 2002; and
- consolidating other partnership and administrative functions.

Failure to timely and successfully integrate our marine transportation business may have a material adverse effect on our business, financial condition and results of operations.

While we do not control Cenac, we will have liability to third parties for its actions in operating our vessels, including negligence, during the period in which the transitional operating agreement is in effect. We will also be exposed to risks that are commonly associated with transactions similar to this acquisition, such as unanticipated liabilities and costs, some of which may be material, and diversion of management’s attention. As a result, the anticipated benefits of the acquisition may not be realized.

Our future debt level or downgrades of our debt ratings by credit agencies may limit our future financial and operating flexibility.

As of February 1, 2008, after giving effect to borrowings under the term credit agreement to retire or redeem the TE Products Senior Notes and to fund a portion of our marine transportation business acquisition, we had approximately $2.2 billion of consolidated debt outstanding, consisting of $520.0 million of borrowings under our revolving credit facility, $715.0 million of borrowings under our term credit agreement, $700.0 million principal amount of Senior Notes and $300.0 million principal amount of junior subordinated notes. The amount of our future debt could have significant effects on our operations, because, among other reasons:

- a significant portion of our cash flow could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our Units and capital expenditures;
- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt; and
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our revolving credit facility and term credit agreement contain restrictive financial and other covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur certain additional indebtedness, make distributions in excess of Available Cash (see Note 13 in the Notes to Consolidated Financial Statements for a discussion of Available Cash), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. These credit agreements also prevent us from making a distribution if an event of default has occurred or would occur as a result of the distribution. Our breach of these restrictions or restrictions in the provisions of our other indebtedness could permit the holders of the indebtedness to declare all amounts outstanding thereunder to be immediately due and payable and, in the case of our revolving credit facility and term credit agreement, to terminate all commitments to extend further credit. Although our revolving credit facility and term credit agreement restrict our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, difficulty accessing capital markets or a reduction in the market price of our Units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates. In addition, a downgrade of our credit ratings could result in us being required to post financial collateral under our guaranty of indebtedness of Centennial and/or some of the contracts that we use in connection with our commodity and interest rate hedging transactions.

Our cash distributions may vary based on our operating performance and level of cash reserves.

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

- the volume of products that we handle and the prices we receive for our services;
- the level of our operating costs;
- the level of competition in our business segments;
- prevailing economic conditions;
- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any; and
- the amount, if any, of cash reserves established by our General Partner in its discretion.

In addition, our ability to pay the minimum quarterly distribution each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make distributions during periods when we record net income.

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

We are a holding company with no material operations. Our only significant assets are the equity interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of their cash to us in order to meet our financial obligations and to allow us to make distributions to our partners. In addition, charter documents and other agreements governing our joint ventures may restrict or limit the occurrence and amount of distributions to us under certain circumstances, including by giving authority to establish available cash for distribution to management committees or other governing bodies that we do not control.

Expanding our natural gas gathering business by constructing new pipelines and compression facilities subjects us to construction risks and risks that natural gas supplies will not be available upon completion of the new pipelines, and cash flows from such capital projects may not be immediate.

We engage in several construction and expansion projects involving existing and new facilities that require significant capital expenditures, which may exceed our estimates. We intend to continue to expand the capacity of our existing natural gas gathering systems through the construction of additional facilities. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities or enter into arrangements such as the Jonah joint venture for the expansion of facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize for a variety of reasons, including because the related reserves are materially lower than we anticipate. As a result, there is the risk that new or expanded facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our financial position or results of operations. Additionally, operating cash flow from a particular project may not be realized until a period of time after its completion or at expected levels. Construction and expansion projects may occur over an extended period of time. If we experience unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

Our tariff rates are subject to review and possible adjustment by federal and state regulators, which could have a material adverse effect on our financial condition and results of operations.

The FERC, pursuant to the Interstate Commerce Act of 1887, as amended, the Energy Policy Act of 1992 and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under that Act, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. Because of the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of our rates could adversely affect our revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. Our interstate tariff rates are either market-based or derived in accordance with the FERC’s indexing methodology, which currently allows a pipeline to increase its rates by a percentage linked to the producer price index for finished goods. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC’s approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

Although our natural gas gathering systems are generally exempt from FERC regulation under the Natural Gas Act of 1938, FERC regulation still significantly affects our natural gas gathering business. In recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue this approach, it could have an adverse effect on the rates we are able to charge in the future. In addition, our natural gas gathering operations could be adversely affected in the future should they become subject to the application of federal regulation of rates and services or if the states in which we operate adopt policies imposing more onerous regulation on gathering. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

Our partnership status may be a disadvantage to us in calculating our cost of service for rate-making purposes.

In May 2005, FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owner of its interests has an actual or potential income tax liability on such income. The policy statement also provides that whether a pipeline's owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. In August 2005, FERC dismissed requests for rehearing of its new policy statement. On December 16, 2005, FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership's rate case. FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16, 2005 order were appealed to the United States Court of Appeals for the District of Columbia Circuit. The D.C. Circuit issued an order on May 29, 2007 in which it denied these appeals and fully upheld FERC's new tax allowance policy and the application of that policy in the December 16 order.

On December 8, 2006, FERC issued a new order addressing rates on another pipeline. In the new order, FERC refined its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a “tax savings.” FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC chose to adjust the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income. On February 7, 2007, the pipeline asked FERC to reconsider this ruling, and the matter remains pending.

On December 26, 2007, FERC issued another order refining its income tax policy for pipeline partnerships. The order generally reaffirmed that the pipeline partnership at issue is entitled to an income tax allowance. Without referencing the December 8, 2006 order, FERC rejected any proposed adjustments to the allowance or to the equity rate of return to account for any timing differences between when an income tax allowance is recovered in rates and when partners are liable for income tax payments. Shippers have asked FERC to reconsider this ruling, and the matter remains pending.

The ultimate outcome of these proceedings is not certain and could result in changes to FERC's treatment of income tax allowances in cost of service. Currently, none of our tariffs are calculated using cost of service rate methodologies. If, however, in the future our tariffs are calculated using a cost of service rate methodology and the policy statement on income tax allowances is modified on judicial review, our revenues might be adversely affected.

Competition could adversely affect our operating results.

Our refined products and LPG transportation business and our marine transportation business compete with other pipelines and barge businesses in the areas where we deliver products. We also compete with trucks and railroads in some of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped or transported. The crude oil gathering and marketing business can be characterized by thin margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production has intensified competition among gatherers and marketers. Our crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies and other companies in the areas where our pipeline systems deliver crude oil and NGLs.

In our natural gas gathering business, new supplies of natural gas are necessary to offset natural declines in production from wells connected to our gathering systems and to increase throughput volume, and we encounter competition in obtaining contracts to gather natural gas supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and price arrangements. Our key competitors in the gas gathering segment include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers we serve, and those producers may also elect to construct proprietary gas gathering systems. If the production delivered to our gathering system declines, our revenues from such operations will decline.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to fully eliminate customer credit risk. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary market areas are located in the Northeast, Midwest and Southwest regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. For the years ended December 31, 2007, 2006 and 2005, Valero accounted for 16%, 14% and 14%, respectively, of our total consolidated revenues, and for the years ended December 31, 2007 and 2006, BP Oil Supply Company accounted for 14% and 11%, respectively, of our total consolidated revenues. Additionally, for the year ended December 31, 2007, Shell Trading Company accounted for 12% of our total consolidated revenues. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2007, 2006 and 2005.

Our risk management policies cannot eliminate all commodity price risks. In addition, any non-compliance with our risk management policies could result in significant financial losses.

To enhance utilization of certain assets and our operating income, we purchase petroleum products. Generally, it is our policy to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to establish a margin for the commodity purchased by selling the same commodity for physical delivery to third party users, such as producers, wholesalers, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product inventory, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity on our pipelines. In addition, our marketing operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved.

Our pipelines are dependent on their interconnections with other pipelines to reach their destination markets.

Decreased throughput on interconnected pipelines due to testing, line repair and reduced pressures could result in reduced throughput on our pipeline systems. Such reduced throughput may adversely impact our profitability.

Reduced demand could affect our pipeline shipments and marine transportation business.

Our business depends in large part on the demand for the various petroleum products we gather, transport and store in the markets we serve. Reductions in that demand adversely affect our business. Market demand varies based upon the different end uses of the petroleum products we gather, transport and store. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, government regulation, technological advances in fuel economy and energy-generation devices, exploration and production activities, and actions by foreign nations, any of which could reduce the demand for the petroleum products in the areas we serve. For example:

- Demand for gasoline, which has in recent years accounted for approximately 55% of our refined products transportation revenues and which we expect will account for a significant portion of transportation revenues in our marine transportation business, depends upon price, prevailing economic conditions and demographic changes in the markets we serve.
- Weather conditions, government 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 approximately 15% of our 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.

The success of our Jonah gas gathering operations is substantially dependent upon Enterprise Products Partners.

We own our interest in the Jonah system, which represents a significant component of our Midstream Segment and its potential for future growth, through a joint venture with Enterprise Products Partners, which is under the common control of Enterprise GP Holdings with us and which is a significant customer of our Midstream Segment (see "– Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs"). The joint venture is governed by a management committee comprised of two representatives approved by an Enterprise Products Partners' affiliate and two representatives approved by subsidiaries of ours, all four of which are EPCO employees. We own an approximate 80.64% interest in the joint venture, with Enterprise Products Partners' affiliate owning the remaining approximate 19.36%. Each representative on the management committee is entitled to one vote, and the joint venture agreement generally requires the affirmative vote of a majority of the members of the management committee to approve an action. Moreover, Enterprise Products Partners is responsible for managing construction of the Phase V expansion of the system. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise Products Partners will each pay our respective ownership share (approximately 80.64% and 19.36%, respectively) of such costs. We and Enterprise Products Partners may not always agree on the best course of action for the joint venture. If such a disagreement were to occur, we would not be able to cause the joint venture to take action that we believed to be in our best interests. Further, Enterprise Products Partners may experience unanticipated delays or costs in construction or operation of the project, which could require additional capital contributions by us and Enterprise Products Partners or diminish expected benefits from the project. Any of these factors could materially and adversely affect our results of operations, financial condition and prospects.

Profits and cash flow from Jonah and Val Verde depend on the volumes of natural gas produced from the fields served by the systems and are subject to factors beyond our control.

Regional production levels drive the volume of natural gas gathered on Jonah and Val Verde. We cannot influence or control the operation or development of the gas fields we serve. For example, production levels may be affected by:

- the absolute price of, volatility in the price of, and market demand for natural gas;
- changes in laws and regulations, particularly with regard to taxes, denial of reduced well density spacing, safety and protection of the environment;
- the depletion rates of existing wells;
- adverse weather and other natural phenomena;
- the availability of drilling and service rigs;
- the availability of labor and skilled personnel; and
- industry changes, including the effect of consolidations or divestitures.

Our gathering systems are connected to natural gas reserves and wells, from which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. The amount of natural gas reserves underlying these wells may also be less than we anticipate, and the rate at which production from these reserves declines may be greater than we anticipate. Accordingly, to maintain or increase throughput levels on our gathering systems, we must continually compete for and obtain new natural gas supplies.

Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems, which depends on a number of factors, including energy prices and other economic and business factors over which we have no control. The primary factors that impact drilling decisions are the prices of oil and natural gas, which reached record levels during 2007. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering systems, which would lead to reduced throughput levels on these systems. Other factors that impact production decisions include producers' capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability and cost of drilling rigs and other drilling equipment, and regulatory changes. Because of these factors, even if new natural gas reserves were discovered in areas served by our systems, producers may choose not to develop those reserves or may connect them to different systems.

In accordance with midstream industry practice, we do not obtain third party evaluations of natural gas reserves dedicated to our gathering systems, including Jonah. Accordingly, volumes of natural gas gathering on our pipeline systems in the future could be less than we anticipate, which could adversely affect our cash flow and our ability to make cash distributions to unitholders.

In accordance with midstream industry practice, we do not obtain third party evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to those systems or the anticipated lives of such reserves. If the total reserves or estimated lives of the reserves connected to our gathering systems, Jonah and Val Verde, are less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas gathered on our systems in the future could be less than we expect. A decline in the volumes of natural gas gathered on our pipeline systems could have an adverse effect on our business, results of operations and financial condition.

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

We historically have sought to limit a portion of the adverse effects resulting from changes in commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed. See Note 6 in the Notes to Consolidated Financial Statements for a discussion of our treasury lock agreements.

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

The DOT issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and take measures to protect pipeline segments located in what the rules refer to as "high consequence areas." The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The ultimate costs of compliance with this rule are difficult to predict. The majority of the costs to comply with the integrity management rule are associated with pipeline integrity testing and the repairs found to be necessary. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in "high consequence areas" can have a significant impact on the costs to perform integrity testing and repairs. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines as required by the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Our operations are subject to governmental laws and regulations relating to the protection of the environment and safety which may expose us to significant costs and liabilities. Additionally, as a result of our marine transportation acquisition, we are subject to additional laws and regulations, including environmental regulations, that may adversely affect the cost, manner or feasibility of doing business in that segment.

Our facilities are subject to multiple environmental, health and safety obligations and potential liabilities under a variety of federal, state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows. We currently own or lease, and have owned or leased, many properties that have been used for many years to terminal or store crude oil, petroleum products or other chemicals. Owners, tenants or users of these properties may have disposed of or released hydrocarbons or solid wastes on or under them. Additionally, some sites we operate are located near current or former refining and terminaling operations. There is a risk that contamination has migrated from those sites to ours.

Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Various state and federal governmental authorities, including the EPA, the Bureau of Land Management, the DOT and OSHA, have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Liability may be incurred without regard to fault under CERCLA, RCRA, and analogous state laws for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipeline systems pass, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage.

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

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. While the costs of remediating groundwater contamination are generally site-specific, such costs can vary substantially and may be material.

Increasingly stringent federal, state and local laws and regulations governing worker health and safety and the manning, construction and operation of marine vessels may significantly affect our marine transportation operations. Many aspects of the marine industry are subject to extensive governmental regulation by the U.S. Coast Guard, the Department of Transportation, the Department of Homeland Security, the National Transportation Safety Board and the U.S. Customs and Border Protection ("CBP"), and to regulation by private industry organizations such as the American Bureau of Shipping. The U.S. Coast Guard and the National Transportation Safety Board set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards. The U.S. Coast Guard is authorized to inspect vessels at will.

Our marine transportation operations are also subject to state and local laws and regulations that control the discharge of pollutants into the environment or otherwise relate to environmental protection. Compliance with such laws, regulations and standards may require installation of costly equipment or operational changes. Failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our marine operations. Some environmental laws often impose strict liability for remediation of spills and releases of oil and hazardous substances, which could subject us to liability without regard to whether we were negligent or at fault. Under the OPA, owners, operators and bareboat charterers are jointly and severally strictly liable for the discharge of oil within the internal and territorial waters of, and the 200-mile exclusive economic zone around, the United States. Additionally, an oil spill from one of our vessels could result in significant liability, including fines, penalties, criminal liability and costs for natural resource damages. The potential for these releases could increase if we increase our fleet capacity. In addition, most states bordering on a navigable waterway have enacted legislation providing for potentially unlimited liability for the discharge of pollutants within their waters.

Our marine transportation business would be adversely affected if we failed to comply with the Jones Act provisions on coastwise trade, or if those provisions were modified, repealed or waived.

As a result of our marine transportation acquisition, we will be subject to the Jones Act and other federal laws that restrict maritime transportation between points in the United States to vessels built and registered in the United States and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our common units and other partnership interests. If we do not comply with these restrictions, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels.

In the past, interest groups have lobbied Congress to repeal the Jones Act to facilitate foreign flag competition for trades and cargoes currently reserved for U.S.-flag vessels under the Jones Act and cargo preference laws. We believe that interest groups may continue efforts to modify or repeal the Jones Act and cargo preference laws currently benefiting U.S.-flag vessels. If these efforts are successful, it could result in increased competition, which could reduce our revenues and cash available for distribution.

The Secretary of the Department of Homeland Security is vested with the authority and discretion to waive the coastwise laws to such extent and upon such terms as he may prescribe whenever he deems that such action is necessary in the interest of national defense. In response to the effects of Hurricanes Katrina and Rita, the Secretary of the Department of Homeland Security waived the coastwise laws generally for the transportation of petroleum products from September 1 to September 19, 2005 and from September 26, 2005 to October 24, 2005. In the past, the Secretary of the Department of Homeland Security has waived the coastwise laws generally for the transportation of petroleum released from the Strategic Petroleum Reserve undertaken in response to circumstances arising from major natural disasters. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign marine vessel operators, which could reduce our revenues and cash available for distribution.

Maritime claimants could arrest the vessels carrying our cargoes.

Crew members, suppliers of goods and services to a vessel, other shippers of cargo and other parties may be entitled to a maritime lien against that vessel for unsatisfied debts, claims or damages. In many jurisdictions, a maritime lienholder may enforce its lien by arresting a vessel through foreclosure proceedings. The arrest or attachment of one of our vessels could substantially delay our shipment. In addition, in some jurisdictions, under the "sister ship" theory of liability, a claimant may arrest both the vessel that is subject to the claimant's maritime lien and any "associated" vessel, which is any vessel owned or controlled by the same owner. Claimants could try to assert "sister ship" liability against one of our vessels for claims relating to a vessel with which we have no relation.

Terrorist attacks aimed at our facilities could adversely affect our business.

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

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to the many hazards inherent in the transportation and terminaling of refined products, LPGs, NGLs, petrochemicals, and crude oil and in the gathering, compressing, and treating of natural gas, including ruptures, leaks, fires, spills, severe weather and other disasters. These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. EPCO maintains insurance coverage on land-based operations on our behalf, although insurance will not cover many types of hazards that might occur, including certain environmental accidents, and will not cover amounts up to applicable deductibles. With respect to our marine operations, until June 30, 2008 or such earlier time as we obtain replacement coverage, we are a named insured on the policies of Cenac which provide for limited hull coverage on our vessels. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, changes in the insurance markets subsequent to the terrorist attacks on September 11, 2001 and the hurricanes of 2005 have made it more difficult for us to obtain certain types of coverage. As a result, EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

We depend on the leadership and involvement of our key personnel for the success of our business.

We depend on the leadership and involvement of our key personnel to identify and develop business opportunities and make strategic decisions. Our president and chief executive officer has over 35 years of relevant experience and our chief financial officer and general counsel each have approximately 20 years of relevant experience. Other senior operational executives who run our business segments have many years of relevant business experience in the areas in which we operate. Any future unplanned departures could have a material adverse effect on our business, financial condition and results of operations. Certain legacy senior executives have compensation agreements in place but officers appointed since our General Partners was acquired by an EPCO affiliate in 2005, including our chief executive officer, are not party to any compensation agreements.

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

We do not own all of the land on which our pipelines and facilities are located, and we are therefore subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for specified periods of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on our business, financial position, results of operations or cash flows.

Mergers among our customers or competitors could result in lower volumes being shipped by us, thereby reducing the amount of cash we generate.

Mergers among our existing customers or competitors could provide strong economic incentives for the combined entities to utilize systems other than ours, and we could experience difficulty in replacing lost volumes and revenues. Because a significant portion of our operating costs are fixed, a reduction in volumes would result not only in a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and make distributions to unitholders.

Risks Relating to Our Units as a Result of Our Partnership Structure

We may issue additional limited partnership interests, diluting existing interests of unitholders and benefiting our General Partner.

Our Partnership Agreement allows us to issue additional Units and other equity securities without unitholder approval. These additional securities may be issued to raise cash or acquire additional assets or businesses or for other partnership purposes. Our Partnership Agreement does not limit the number of Units and other equity securities we may issue. If we issue additional Units or other equity securities, the proportionate partnership interest and voting power of our existing unitholders will decrease and the ratio of taxable income to distributions may increase. Such issuances could negatively affect the amount of cash distributed to unitholders and the market price of our Units.

Cost reimbursements and fees due EPCO and its affiliates may be substantial and will reduce our cash available for distribution to holders of our Units.

Prior to making any distribution on our Units, we will reimburse EPCO and its affiliates, including our General Partner, for expenses they incur on our behalf for operations and management functions. The payment of these amounts and allocated overhead to EPCO and its affiliates could adversely affect our ability to pay cash distributions to holders of our Units. These amounts include all costs in managing and operating our business, including compensation of executives for time allocated to us, director compensation, costs for rendering administrative staff and support services and overhead allocated to us by EPCO. Please read “Item 13. Certain Relationships and Related Transactions, and Director Independence” in this Report. In addition, our General Partner and its affiliates may provide other services to us for which we will be charged fees as determined by our General Partner.

Our General Partner and its affiliates may have conflicts with our partnership.

The directors and officers of our General Partner and its affiliates (including Enterprise GP Holdings, EPCO and other affiliates of EPCO) have duties to manage the General Partner in a manner that is beneficial to its owner, Enterprise GP Holdings, which is controlled by Dan L. Duncan. At the same time, the General Partner has duties to manage us in a manner that is beneficial to us. Enterprise GP Holdings also controls other publicly traded partnerships, Enterprise Products Partners and Duncan Energy Partners, that engage in similar lines of business. We have significant business relationships with Enterprise Products Partners, EPCO and other entities controlled by

Dan L. Duncan. Mr. Duncan's economic interests in Enterprise Products Partners and these other related entities are more substantial than his economic interest in us. Therefore, our General Partner's duties to us may conflict with the duties of its officers and directors to its owner. As a result of these conflicts of interest, our General Partner may favor its own interest or those of Enterprise GP Holdings or its owners over the interest of our unitholders. Possible conflicts may include, among others, the following:

- Enterprise GP Holdings, Enterprise Products Partners, EPCO and their affiliates may engage in substantial competition with us on the terms set forth in the ASA.
- Neither our Partnership Agreement nor any other agreement requires entities that control our General Partner or other entities controlled by Mr. Duncan (other than our General Partner) to pursue a business strategy that favors us. Directors and officers of EPCO, the general partner of Enterprise GP Holdings and the general partner of Enterprise Products Partners and their affiliates have a fiduciary duty to make decisions in the best interest of their members, shareholders or unitholders, as the case may be, which may be contrary to our interests.
- Our General Partner is allowed to take into account the interests of parties other than us, such as Enterprise GP Holdings, Enterprise Products Partners and their affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- Some of the officers of EPCO who provide services to us also may devote significant time to the business of Enterprise Products Partners or its other affiliates and will be compensated by EPCO for such services.
- Our Partnership Agreement limits the liability and reduces the fiduciary duties of our General Partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing Units, unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.
- Our General Partner determines the amount and timing of asset purchases and sales, operating expenditures, capital expenditures, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders.
- Our General Partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us.
- Our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our General Partner generally seeks to limit its liability regarding our contractual obligations.
- Our General Partner may exercise its rights to call and purchase all of our Units if at any time it and its affiliates own 85% or more of the outstanding Units.
- Our General Partner controls the enforcement of obligations owed to us by it and its affiliates, including the ASA.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please read "Item 13. Certain Relationships and Related Party Transactions, and Director Independence" in this Report.

Unitholders have limited voting rights and control of management.

Our General Partner manages and controls our activities. Unitholders have no right to elect the General Partner or the directors of the General Partner on an annual or other ongoing basis. However, if the General Partner resigns or is removed, its successor may be elected by holders of a majority of the Units. Unitholders may remove the General Partner only by a vote of the holders of at least 66 $^{2}/3$% of the Units. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations. As a result, unitholders will have limited influence on matters affecting our operations, and third parties may find it difficult to gain control of us or influence our actions.

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

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

The ASA governs business opportunities among entities controlled by our General Partner, including us ("TEPPCO Companies"), entities controlled by the general partners of Enterprise GP Holdings and Enterprise Products Partners, including Enterprise GP Holdings and Enterprise Products Partners ("Enterprise Companies"), Duncan Energy Partners and its general partner and EPCO and its other affiliates. Under the ASA, we have no obligation to present any business opportunity offered to or discovered by us to the Enterprise Companies, and they are not obligated to present business opportunities that are offered to or discovered by them to us. However, the agreement requires that business opportunities offered to or discovered by EPCO, which is affiliated with both the TEPPCO Companies and the Enterprise Companies, be offered first to certain Enterprise Companies before they may be pursued by EPCO and its other affiliates or offered to us.

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

Our Partnership Agreement limits our General Partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our Partnership Agreement:

- permits our General Partner to make a number of decisions on its behalf, as opposed to in its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right with respect to Units, its registration rights and the determination of whether to consent to any merger or consolidation of the Partnership or amendment to the Partnership Agreement;
- provides that, in the absence of bad faith by the ACG Committee of the board of directors of our General Partner or our General Partner, the resolution, action or terms made, taken or provided by the ACG Committee or our General Partner in connection with a potential conflict of interest transaction will be conclusive and binding on all persons (including all partners) and will not constitute a breach of the Partnership Agreement or any standard of care or duty imposed by law;
- provides that any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if approved by the ACG Committee or is on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third party;
- provides that the General Partner shall not be liable to the Partnership or any partner for its good faith reliance on the provisions of the Partnership Agreement to the extent it has duties, including fiduciary duties, and liabilities at law or in equity;
- provides that it shall be presumed that the resolution of any conflicts of interest by our General Partner or the audit and conflicts committee of the board of directors of our General Partner was not made in bad faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

- provides that our General Partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

Our General Partner has a limited call right that may require unitholders to sell their Units at an undesirable time or price.

If at any time persons other than our General Partner and its affiliates own less than 15% of the Units then outstanding, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining Units held by unaffiliated persons at a price not less than the then-current market price. As a result, unitholders may be required to sell their Units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon a sale of their Units.

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

Under Delaware law, our General Partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our General Partner. Further, unitholders could be held liable for our obligations to the same extent as a General Partner if a court determined that:

- we were conducting business in a state, but had not complied with that particular state's partnership statute; or
- the right of limited partners to remove our General Partner or to take other action under our Partnership Agreement constituted participation in the "control" of our business.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a limited partner may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

The credit and risk profile of our General Partner and its owners could adversely affect our credit ratings and profile, which could increase our borrowing costs or hinder our ability to raise capital.

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

Entities controlling the owner of our General Partner have significant indebtedness outstanding and are dependent principally on the cash distributions from the general partner and limited partner equity interests in us, Enterprise GP Holdings, Enterprise Products Partners and Energy Transfer Equity, L.P. to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect our separateness from our General Partner and the entities that control our General Partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of Dan L. Duncan or the entities that control our General Partner were viewed as substantially lower or more risky than ours. In addition, the 100% membership interest in our General Partner and the 4,400,000 of our Units that are owned by Enterprise GP Holdings are pledged under Enterprise GP Holdings' credit facility. Upon an event of default under that credit facility, the lenders could foreclose on Enterprise GP Holdings' assets, which could ultimately result in a change in control of our General Partner and a change in the ownership of our Units held by Enterprise GP Holdings.

Control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of Enterprise GP Holdings from transferring all or a portion of its ownership interest in our General Partner to a third party. Such a third party would then be in a position to replace the board of directors and officers of our General Partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Tax Risks to Unitholders

We have adopted certain methodologies that may result in a shift of income, gain, loss and deduction between the General Partner and our unitholders. The Internal Revenue Service (“IRS”) may challenge this treatment, which could adversely affect the value of our Units.

When we issue additional Units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our General Partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the General Partner, which may be unfavorable to such unitholders. Moreover, under this methodology, subsequent purchasers of Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the General Partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders’ sale of Units and could have a negative impact on the value of the Units or result in audit adjustments to our unitholders’ tax returns without the benefit of additional deductions.

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

The anticipated after-tax economic benefit of an investment in the Units depends largely on our being treated as a partnership for federal income tax purposes. Because we are a publicly traded partnership, this requires that 90% or more of our gross income for every taxable year consist of qualifying income, as defined in Section 7704 of the Internal Revenue Code (the “Qualifying Income Requirement”). We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level federal income taxation. Our Partnership Agreement currently provides that if a law is enacted that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution amount and the target distribution level will be adjusted to reflect the impact of that law on us, including any related imposition of state and local income taxes.

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are subject to a new entity-level tax on the portion of our income generated in Texas. Specifically, the revised Texas franchise tax is imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such tax on us by Texas, or any other state, will reduce the cash available for distribution to you.

Our tax treatment as a partnership for federal income tax purposes is subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

Our treatment as a partnership for federal income tax purposes may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the Qualifying Income Requirement, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our Units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Internal Revenue Code Section 7704(d) and the treatment of certain types of income earned from profits interests in partnerships. It is possible that these efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. We are unable to predict whether any of these changes, or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our Units.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our Units, and the cost of an IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

Tax gain or loss on the disposition of Units could be more or less than expected.

If you sell your Units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those Units. Prior distributions to you in excess of the total net taxable income you were allocated for a Unit, which decreased your tax basis in that Unit, will, in effect, become taxable income to you if you sell the Unit at a price greater than your tax basis in that Unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. If you sell your Units, you may incur a tax liability in excess of the amount of cash you receive from the sale. If the IRS successfully contests some positions we take, unitholders could recognize more gain on the sale of Units than would be the case under those positions, without the benefit of decreased income in prior years.

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

Investment in Units by tax-exempt entities, such as individual retirement accounts (“IRAs”), other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person you should consult your tax advisor before investing in our Units.

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

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

Unitholders may be subject to foreign, state and local taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our Units.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. Our operating subsidiaries own assets and do business in Alabama, Arkansas, Colorado, Illinois, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Texas, Utah, West Virginia and Wyoming. Each of these states, other than South Dakota, Texas and Wyoming currently imposes a personal income tax and many impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, state and local, as well as foreign tax returns.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. If this occurs, you will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to you with respect to that period.

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

None.

Item 3. ***Legal Proceedings***

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs assert damages attributable to the remediation of the property of approximately $1.4 million. This case has been stayed pending the completion of remediation pursuant to the Louisiana Department of Environmental Quality ("LDEQ") requirements. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of our other unitholders, and derivatively on our behalf, concerning proposals made to our unitholders in our definitive proxy statement filed with the SEC on September 11, 2006 (“Proxy Statement”) and other transactions involving us and Enterprise Products Partners or its affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants the General Partner; the Board of Directors of the General Partner; EPCO; Enterprise Products Partners and certain of its affiliates and Dan L. Duncan. We are named as a nominal defendant.

The amended complaint alleges, among other things, that certain of the transactions adopted at a special meeting of our unitholders on December 8, 2006, including a reduction of the General Partner’s maximum percentage interest in our distributions in exchange for Units (the “Issuance Proposal”), were unfair to our unitholders and constituted a breach by the defendants of fiduciary duties owed to our unitholders and that the Proxy Statement failed to provide our unitholders with all material facts necessary for them to make an informed decision whether to vote in favor of or against the proposals. The amended complaint further alleges that, since Mr. Duncan acquired control of the General Partner in 2005, the defendants, in breach of their fiduciary duties to us and our unitholders, have caused us to enter into certain transactions with Enterprise Products Partners or its affiliates that were unfair to us or otherwise unfairly favored Enterprise Products Partners or its affiliates over us. The amended complaint alleges that such transactions include the Jonah joint venture entered into by us and an Enterprise Products Partners’ affiliate in August 2006 (citing the fact that our ACG Committee did not obtain a fairness opinion from an independent investment banking firm in approving the transaction), and the sale by us to an Enterprise Products Partners affiliate of the Pioneer plant in March 2006. As more fully described in the Proxy Statement, the ACG Committee recommended the Issuance Proposal for approval by the Board of Directors of the General Partner. The amended complaint also alleges that Richard S. Snell, Michael B. Bracy and Murray H. Hutchison, constituting the three members of the ACG Committee, cannot be considered independent because of their alleged ownership of securities in Enterprise Products Partners and its affiliates and/or their relationships with Mr. Duncan.

The amended complaint seeks relief (i) awarding damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; (ii) rescinding all actions taken pursuant to the Proxy vote and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts.

In 1999, our Arcadia, Louisiana, facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of environmental contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At December 31, 2007, we have an accrued liability of $0.6 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice (“DOJ”) of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the EPA, was seeking a civil penalty against us for alleged violations of the CWA arising out of this release, as well as three smaller spills at other locations in 2004 and 2005. We agreed with the DOJ on a penalty of approximately $2.9 million, along with our commitment to implement additional spill prevention measures. In August 2007, we deposited $2.9 million into a restricted cash account per the terms of the settlement, and in October 2007, we paid the $2.9 million plus interest earned on the amount to the DOJ. This settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

One of the spills encompassed in our current settlement discussion with the DOJ involved a 37,450-gallon release from Seaway on May 13, 2005 at Colbert, Oklahoma. This release was remediated under the supervision of the Oklahoma Corporation Commission, but resulted in claims by neighboring landowners that have been settled for approximately $1.0 million. In addition, the release resulted in a Corrective Action Order by the DOT. Among other requirements of this Order, we were required to reduce the operating pressure of Seaway by 20% until completion of required corrective actions. The corrective actions were completed and on June 1, 2006, we increased the operating pressure of Seaway back to 100%. We have a 50% ownership interest in Seaway, and our share of the settlement was covered by our insurance. The settlement of the Colbert release did not have a material adverse effect on our financial position, results of operations or cash flows.

We are also in negotiations with the DOT with respect to a notice of probable violation that we received on April 25, 2005, for alleged violations of pipeline safety regulations at our Todhunter facility, with a proposed $0.4 million civil penalty. We responded on June 30, 2005, by admitting certain of the alleged violations, contesting others and requesting a reduction in the proposed civil penalty. We do not expect any settlement, fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows.

On February 24, 2005, the General Partner was acquired from DCP by DFIGP. The General Partner owns a 2% general partner interest in us and is our general partner. On March 11, 2005, the Bureau of Competition of the FTC delivered written notice to DFIGP’s legal advisor that it was conducting a non-public investigation to determine whether DFIGP’s acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. We and our General Partner cooperated fully with this investigation.

On October 31, 2006, an FTC order and consent agreement ending its investigation became final. The order required the divestiture of our equity interest in MB Storage, its general partner and certain related assets to one or more FTC-approved buyers in a manner approved by the FTC and subject to its final approval. The order contained no minimum price for the divestiture and required that we provide the acquirer or acquirers the opportunity to hire employees who spend more than 10% of their time working on the divested assets. The order also imposed specified operational, reporting and consent requirements on us including, among other things, in the event that we acquire interests in or operate salt dome storage facilities for NGLs in specified areas. The FTC approved a buyer and sale terms for our equity interests and certain related assets, and we closed on such sale on March 1, 2007.

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

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

None.

PART II

Item 5. *Market for Registrant's Units and Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our Units are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "TPP". The high and low trading prices of our Units in 2007 and 2006, respectively, as reported on the NYSE, were as follows:

	2007		2006	
Quarter	High	Low	High	Low
First	$44.53	$39.88	$39.00	$35.29
Second	46.20	42.15	38.49	35.20
Third	46.01	37.04	37.65	34.44
Fourth	40.81	37.17	41.86	36.90

Based on the information received from our transfer agent, as of February 1, 2008, there were approximately 1,272 unitholders of record of our Units.

The quarterly cash distributions on our Units for the years ended December 31, 2007 and 2006, were as follows:

Record Date	Payment Date	Amount Per Unit
April 28, 2006	May 5, 2006	$0.675
July 31, 2006	August 7, 2006	0.675
October 31, 2006	November 7, 2006	0.675
January 31, 2007	February 7, 2007	0.675
April 28, 2007	May 7, 2007	0.685
July 31, 2007	August 7, 2007	0.685
October 31, 2007	November 7, 2007	0.695
January 31, 2008	February 7, 2008	0.695

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds (see Note 13 in the Notes to Consolidated Financial Statements).

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

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

Recent Sales of Unregistered Securities

On February 1, 2008, we issued 4,434,005 Units to Cenac Towing Co., Inc. and 420,894 Units to Mr. Arlen B. Cenac, Jr. in conjunction with the acquisition of our marine transportation business. The Units were issued in reliance upon the exemption from the registration requirements of the Securities Act of 1933, as amended, afforded by Section 4(2) in reliance upon certain investment representations and warranties in the marine transportation business purchase agreement relating to the knowledge and experience in financial and business matters of the Seller Parties.

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Units Authorized for Issuance Under Equity Compensation Plan

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

Issuer Purchases of Equity Securities

We did not repurchase any of our Units during 2007.

Item 6. *Selected Financial Data*

The following tables set forth, for the periods and at the dates indicated, our selected consolidated financial data, which is derived from our audited consolidated financial statements, and our selected operating data. The selected financial data as of and for the years ended December 31, 2006, 2005 and 2004 reflect Jonah's Pioneer plant, which was sold on March 31, 2006, as discontinued operations. The financial data should be read in conjunction with our audited consolidated financial statements included in the Index to Consolidated Financial Statements on page F-1 of this Report. See also Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in thousands, except per Unit amounts)				
Income Statement Data:					
Operating revenues:					
Sales of petroleum products	$9,147,104	$9,080,516	$8,061,808	$5,426,832	$3,766,651
Transportation – Refined products	170,231	152,552	144,552	148,166	138,926
Transportation – LPGs	101,076	89,315	96,297	87,050	91,787
Transportation – Crude oil	45,952	38,822	37,614	37,177	29,057
Transportation – NGLs	46,542	43,838	43,915	41,204	39,837
Gathering – Natural gas	61,634	123,933	152,797	140,122	135,144
Other revenues	85,521	78,509	68,051	67,539	54,430
Total operating revenues	9,658,060	9,607,485	8,605,034	5,948,090	4,255,832
Purchases of petroleum products	9,017,109	8,967,062	7,986,438	5,367,027	3,711,207
Operating expenses (1)	271,167	278,448	255,359	257,372	235,028
General and administrative expenses	33,657	31,348	33,143	28,016	20,409
Depreciation and amortization	105,225	108,252	110,729	112,284	100,728
Gains on sales of assets	(18,653)	(7,404)	(668)	(1,053)	(3,948)
Operating income	249,555	229,779	220,033	184,444	192,408
Interest expense – net	(101,223)	(86,171)	(81,861)	(72,053)	(84,250)
Gain on sale of ownership interest in MB Storage	59,628	—	—	—	—
Equity earnings	68,755	36,761	20,094	22,148	12,874
Other income – net (including interest income)	3,022	2,965	1,135	1,320	748
Income before provision for income taxes	279,737	183,334	159,401	135,859	121,780
Provision for income taxes	557	652	—	—	—
Income from continuing operations	279,180	182,682	159,401	135,859	121,780
Discontinued operations (2)	—	19,369	3,150	2,689	—
Net income	$ 279,180	$ 202,051	$ 162,551	$ 138,548	$ 121,780
Basic and diluted income per Unit: (3)					
Continuing operations	$ 2.60	$ 1.77	$ 1.67	$ 1.53	$ 1.47
Discontinued operations (2)	—	0.19	0.04	0.03	—
Net income per Unit	$ 2.60	$ 1.96	$ 1.71	$ 1.56	$ 1.47

	December 31, 2007	2006	2005	2004	2003
			(in thousands)		
Balance Sheet Data:					
Property, plant and equipment – net	$1,793,634	$1,642,095	$1,960,068	$1,703,702	$1,619,163
Total assets	4,750,057	3,922,092	3,680,538	3,186,284	2,934,480
Total short-term debt	353,976	—	—	—	—
Total long-term debt	1,511,083	1,603,287	1,525,021	1,480,226	1,339,650
Partners' capital	1,264,627	1,320,330	1,201,370	1,011,103	1,102,809

	For Year Ended December 31, 2007	2006	2005	2004	2003
			(in thousands, except per Unit amounts)		
Cash Flow Data:					
Net cash provided by continuing operating activities (2)	$ 350,572	$ 271,552	$ 250,723	$ 263,896	$ 242,424
Net cash provided by operating activities	350,572	273,073	254,505	267,167	242,424
Capital expenditures to sustain existing operations (4)	(52,149)	(39,966)	(40,783)	(41,733)	(32,864)
Capital expenditures	(228,272)	(170,046)	(220,553)	(156,749)	(126,707)
Distributions paid	(294,450)	(278,566)	(251,101)	(233,057)	(202,498)
Distributions paid per Unit (3)	$ 2.74	$ 2.70	$ 2.68	$ 2.64	$ 2.50

(1) Includes operating fuel and power and taxes – other than income taxes.

(2) Reflects the Pioneer plant as discontinued operations for the years ended December 31, 2004, 2005 and 2006. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004.

(3) Per Unit calculation includes 9,188,957 Units issued in 2003, net of retirement of Class B Units of 3,916,547. No Units were issued in 2004. In 2005 and 2006, 6,965,000 Units and 5,750,000 Units were issued, respectively. On December 8, 2006, we issued 14,091,275 Units to our General Partner in consideration for a reduction in the incentive distribution rights of the General Partner. In 2007, 106,703 Units were issued.

(4) Capital expenditures to sustain existing operations include projects required by regulatory agencies or required life-cycle replacements.

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

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

- Overview of Business.
- Critical Accounting Policies and Estimates – Presents accounting policies that are among the most critical to the portrayal of our financial condition and results of operations.
- Results of Operations – Discusses material period-to-period variances in the statements of consolidated income.
- Financial Condition and Liquidity – Analyzes cash flows and financial position.
- Other Considerations – Addresses available sources of liquidity, trends, future plans and contingencies that are reasonably likely to materially affect future liquidity or earnings.
- Recent Accounting Pronouncements.

This discussion contains forward-looking statements based on current expectations that are subject to risks and uncertainties, such as statements of our plans, objectives, expectations and intentions. Our actual results and the timing of events could differ materially from those anticipated or implied by the forward-looking statements discussed here as a result of various factors, including, among others, those set forth under the "Cautionary Note Regarding Forward-Looking Statements" and "Risk Factors" herein.

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Overview of Business

Certain factors are key to our operations. These include the safe, reliable and efficient operation of the pipelines and facilities that we own or operate while meeting the regulations that govern the operation of our assets and the costs associated with such regulations. Through December 31, 2007, we operated and reported in three business segments:

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

On February 1, 2008, with the acquisition of the marine transportation business, we began operating and reporting in a fourth business segment, Marine Transportation Segment. See "Items 1 and 2. Business and Properties, Marine Transportation Segment – Barge Transportation of Petroleum Products" for further information.

Consistent with our business strategy, we are also focused on continued growth through expansion of the assets that we own and through the construction and acquisition of assets. We continuously evaluate possible acquisitions of assets that would complement our current operations, including assets which, if acquired, would have a material effect on our financial position, results of operations or cash flows.

Downstream Segment

Our Downstream Segment revenues are earned from transportation, marketing and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Our Downstream Segment transportation activities generate revenue primarily through tariffs filed with the FERC applicable to shippers of refined products and LPGs on our pipelines. Our refined products marketing activities generate revenues by purchasing refined products from our throughput partners and establishing a margin by selling refined products for physical delivery through spot sales at the Aberdeen truck rack to third-party wholesalers and retailers of refined products. These purchases and sales are generally contracted to occur on the same day. Storage revenue is generated from fees based on storage volumes contracted for by customers.

Our Downstream Segment is dependent in large part on the demand for refined products and LPGs in the markets served by its pipelines and the availability of alternative supplies to serve those markets. As such, quantities and mix of products transported may vary. Market demand for refined products shipped in the Downstream Segment varies based upon the different end uses of the products, while transportation tariffs vary among specific product types. Demand for gasoline, which in recent years has accounted for approximately 55% of the Downstream Segment's refined products transportation revenues, depends upon market price, prevailing economic conditions, demographic changes in the markets served in the Downstream Segment and availability of gasoline produced in refineries located in those markets. Generally, higher market prices of gasoline has little impact on deliveries in the short-term, but may have a more significant impact on us in the long-term due to long lead times associated with expansion of refinery production capacities and conversion of the auto fleets to more fuel efficient models. Demand for distillates, which in recent years has accounted for approximately 30% of the Downstream Segment's refined products transportation revenues, is affected by truck and railroad freight, the price of natural gas used by utilities, which use distillates as a substitute for natural gas when the price of natural gas is high, and usage for agricultural operations, which is affected by weather conditions, government policy and crop prices. Demand for jet fuel, which in recent years has accounted for approximately 15% of the Downstream Segment's refined products revenues, depends on prevailing economic conditions and military usage. Increases in the market price of jet fuel and the impact on airlines has resulted in the use of more efficient airplanes and reductions in total capacity and the number of scheduled flights. High market price of propane could result in the use of alternative fuel sources and tend to reduce the summer and early fall fill of consumer storage of propane. As a result, market price volatility may affect transportation volumes and revenues from period to period.

The mix of products delivered by our Downstream Segment varies seasonally. We generally realize higher revenues in the Downstream Segment during the first and fourth quarters of each year since LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating, and due to the demand for normal butane, which is used for the blending of gasoline. 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. The two largest operating expense items of the Downstream Segment are labor and electric power. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports RGP from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investment in Centennial (see Note 9 in the Notes to Consolidated Financial Statements).

Upstream Segment

Our Upstream Segment revenues are earned from gathering, transporting, marketing and storing crude oil, and distributing lubrication oils and specialty chemicals principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale or delivery of the crude oil to local refineries, marketers or other end users. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas.

The areas served by our gathering and transportation operations are geographically diverse, and the forces that affect the supply of the products gathered and transported vary by region. Crude oil prices and production levels affect the supply of these products. The demand for gathering and transportation is affected by the demand for crude oil by refineries, refinery supply companies and similar customers in the regions served by this business, as well as by production levels in the regions served.

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

Our Upstream Segment also includes our equity investment in Seaway (see Note 9 in the Notes to Consolidated Financial Statements). Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas. Additionally, we completed a project in our South Texas system that allows Seaway to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing.

Midstream Segment

Our Midstream Segment revenues are earned from the gathering of coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and fractionation of NGLs in Colorado. Under its gathering agreements, Val Verde gathers the natural gas supplied to its gathering systems and redelivers the natural gas for a fixed fee. CBM volumes gathered on the Val Verde system have begun to decline, primarily due to the natural decline of CBM production by the producers in the field. Transportation revenues are recognized as NGLs are delivered for customers. Fractionation revenues are recognized ratably over the contract year as products are delivered. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances. Therefore, the results of our Midstream Segment have not been materially affected by changes in the prices of natural gas or NGLs.

Our Midstream Segment also includes our equity investment in Jonah (see Note 9 in the Notes to Consolidated Financial Statements). Jonah, which is a joint venture between us and an affiliate of Enterprise Products Partners, owns a natural gas gathering system in the Green River Basin in southwestern Wyoming. Under its gathering agreements, Jonah gathers and compresses the natural gas supplied to its gathering system and redelivers the natural gas to gas processing facilities and interstate pipelines located in the region for a fixed fee. Prior to August 1, 2006, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective August 1, 2006, we entered into the joint venture with Enterprise Product Partners' affiliate, upon which Jonah was deconsolidated, and its operating results since August 1, 2006, have been accounted for under the equity method of accounting. Operating results of the Pioneer plant, which was part of our Midstream Segment and which we sold to an Enterprise Products Partners' affiliate in March 2006, are shown as discontinued operations for the years ended December 31, 2006 and 2005.

Other than the effects of normal operating pressure fluctuations, we can neither influence nor control the operation, development or production levels of the gas fields served by the Jonah and Val Verde systems, which may be affected by price and price volatility, market demand, depletion rates of existing wells and changes in laws and regulations.

Marine Transportation Segment

Most of our marine transportation revenue is expected to be derived from term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from designated origins to designated destinations at set day rates. Most of the term contracts we are acquiring from Cenac have one-year terms with the remainder having terms of up to two years. All of the existing contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. We do not assume ownership of the products we transport in this segment. As is typical for inland liquid affreightment contracts, the term contracts we are acquiring establish firm day rates but do not include revenue or volume guarantees. Most of the contracts include escalation provisions to recover specific increased operating costs such as incremental increases in labor and equipment retrofits required by emerging government regulation. The costs of fuel and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts. We use a voyage accounting method of revenue recognition for our marine transportation revenues which allocates voyage revenue and expenses based on the percent of the voyage completed during the period. A decline in demand for, and level of consumption of, refined products could cause demand for tank vessel capacity and charter rates to decline, which would decrease our revenues and profitability.

Business Trends

We believe the trends or factors identified below will drive our growth opportunities in 2008 and beyond and have identified below, with each trend or factor, the related strategies or opportunities we believe these factors present.

- We expect that refined products imports to the U.S. will increase.
  - Acquire or develop facilities to take advantage of the increased volumes.
  - Enhance refined products storage business.
- We expect to see turnover in commercial terminal ownership and operations.
  - Acquire refined products terminals and distribution assets to provide logistical service offerings to companies seeking to outsource or partner.
- We expect that Canadian crude oil imports to the U.S. will increase.
  - Develop competitive options to move Canadian crude oil to U.S. refining customers with third parties through an optimum combination of new pipeline construction and existing pipeline assets.
- We expect that crude oil imports to the U.S. Gulf Coast will increase.
  - Build onshore or offshore crude oil discharge, handling and transportation facilities to optimize the U.S. Gulf Coast marine delivery options for imported crude oil.

  - o Strengthen market position around our existing market base by focusing on activities in West Texas, South Texas and Red River areas, align Seaway Crude Pipeline Company with key refiners and suppliers and increase margins by expanding services and managing costs.
  - o Focus on new refinery supply markets with existing assets and expand our asset base in the upper Texas Gulf Coast as well as utilize the existing Cushing, Oklahoma, storage for mid-continent refineries and other customers.
- We expect the demand for marine transportation services in our market areas to remain strong.
  - o Expand our current barge capacity through new construction or acquisition.
  - o Utilize our newly acquired marine transportation business, which complements our existing strategy of developing a network of terminals along the nation’s inland and coastal waterways, to extend the logistical services to our existing and new customers.
- We expect to see continued expansion opportunities for natural gas gathering and related services in the Jonah, Pinedale and San Juan Basin areas.
  - o Continue development and expansion of the Jonah system which serves the Jonah and Pinedale fields in our Midstream Segment.
  - o Add new volumes and improve the operating efficiency of the Val Verde system in our Midstream Segment in New Mexico’s San Juan Basin, through new connections of conventional and Colorado coal seam gas.
  - o Capitalize on our assets that are positioned in active producing areas important to future domestic gas supply.
- Standards for use of ethanol and other renewable fuels are currently mandated to increase to 15 billion gallons by 2015 and will ultimately reach 36 billion gallons per year under newly passed energy legislation.
  - o Capitalize on blending and logistical business opportunities at our existing terminal locations and participate in the overall supply and distribution of ethanol.

We also believe other growth opportunities are available to us, including: expanding our West Texas crude oil system and storage capacity at Cushing in our Upstream Segment; increasing throughput on our Midstream Segment NGL systems; expanding our Downstream Segment system delivery capability of refined products to our Midwest markets experiencing a supply shortfall; utilizing available capacity of Centennial to further support increased refined products movements to Midwest market areas, and also support increased movements of long-haul propane volumes; expanding our Downstream Segment gathering capacity of refined products along the upper Texas Gulf Coast; and pursuing acquisitions or organic growth projects that would complement our current operations. We cannot assure that management will achieve all or any of these objectives or those described above.

Recently, crude oil is trading near $100 per barrel. At these price levels, the cost of motor gasoline to consumers is expected to increase. Also, certain business sectors of the U.S economy, including housing and autos have experienced relatively weak economic conditions. Should motor gasoline prices remain elevated for an extended period and/or should weak economic conditions in the U.S become more widespread for a prolonged period of time, consumers could exercise conservation measures to reduce their demand for motor gasoline. Should this happen, volumes of motor gasoline handled by our pipeline and terminal facilities may decrease.

Consistent with our business strategy, we continuously evaluate possible acquisitions of assets that would complement our current operations, including assets which, if acquired, would have a material effect on our financial position, results of operations or cash flows.

Critical Accounting Policies and Estimates

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

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

Revenue and Expense Accruals

We routinely make accruals based on estimates for both revenues and expenses due to the timing of compiling billing information, receiving certain third party information and reconciling our records with those of third parties. The delayed information from third parties includes, among other things, actual volumes of crude oil purchased, transported or sold, adjustments to inventory and invoices for purchases, actual natural gas and NGL deliveries and other operating expenses. We make accruals to reflect estimates for these items based on our internal records and information from third parties. Most of the estimated accruals are reversed in the following month when actual information is received from third parties and our internal records have been reconciled.

The most difficult accruals to estimate are power costs, property taxes and crude oil margins. Power cost accruals generally involve a two to three month estimate, and the amount varies primarily for actual power usage. Power costs are dependent upon the actual volumes transported through our pipeline systems and the various power rates charged by numerous power companies along the pipeline system. Peak demand rates, which are difficult to predict, drive the variability of the power costs. For the year ended December 31, 2007, approximately 9% of our power costs were recorded using estimates. A variance of 10% in our aggregate estimate for power costs would have an approximate $0.5 million impact on annual earnings. Property tax accruals involve significant tax rate estimates in numerous jurisdictions. Actual property taxes are often not known until the tax bill is settled in subsequent periods, and the tax amount can vary for tax rate changes and changes in tax methods or elections. A variance of 10% in our aggregate estimate for property taxes could have up to an approximate $1.1 million impact on annual earnings. Crude oil margin estimates are based upon historical crude oil marketing volumes, factoring in current market events and prices of crude oil. We use an average of prices that were in effect during the applicable month to determine the expected revenue amount, and we determine the margin by evaluating the actual margins of the prior twelve months. As of December 31, 2007, approximately 2% of our annual crude oil margin is recorded using estimates. A variance from this estimate of 10% would impact the net of revenues and purchases by approximately $0.4 million on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Reserves for Environmental Matters

At December 31, 2007, we have accrued a liability of $4.0 million for our estimate of the future payments we expect to pay for environmental costs to remediate existing conditions attributable to past operations, including conditions with assets we have acquired. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations. A variance of 10% in our aggregate estimate for environmental costs would have an approximate $0.4 million impact on annual earnings. For information concerning environmental regulation and environmental costs and contingencies, see Items 1 and 2. Business and Properties, "– Environmental and Safety Matters".

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Some of these circumstances include changes in laws and regulations relating to restoration and abandonment requirements; changes in expected costs for dismantlement, restoration and abandonment as a result of changes, or expected changes, in labor, materials and other related costs associated with these activities; changes in the useful life of an asset based on the actual known life of similar assets, changes in technology, or other factors; and changes in expected salvage proceeds as a result of a change, or expected change in the salvage market. At December 31, 2007 and 2006, the net book value of our property, plant and equipment was $1,793.6 million and $1,642.1 million, respectively. We recorded $81.1 million, $78.9 million and $80.2 million in depreciation expense during the years ended December 31, 2007, 2006 and 2005, respectively.

We regularly review long-lived assets for impairment in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Such events or changes include, among other factors: operating losses, unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products in a market area; changes in competition and competitive practices; and changes in governmental regulations or actions. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated future undiscounted net cash flows expected to be generated by the asset. Estimates of future undiscounted net cash flows include anticipated future revenues, expected future operating costs and other estimates. Such estimates of future undiscounted net cash flows are highly subjective and are based on numerous assumptions about future operations and market conditions. 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 estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell.

Goodwill and Intangible Assets

Goodwill and intangible assets represent the excess of consideration paid over the estimated fair value of tangible net assets acquired. Certain assumptions and estimates are employed in determining the estimated fair value of assets acquired including goodwill and other intangible assets as well as determining the allocation of goodwill to the appropriate reporting unit. In addition, we assess the recoverability of these intangibles by determining whether the amortization of these intangibles over their remaining useful lives can be recovered through undiscounted estimated future net cash flows of the acquired operations. The amount of impairment, if any, is measured by the amount by which the carrying amounts exceed the projected discounted estimated future operating cash flows.

During 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinues the amortization of goodwill and intangible assets that have indefinite lives and requires an annual test of impairment based on a comparison of the estimated fair value to carrying values. The evaluation of impairment for goodwill and intangible assets with indefinite lives under SFAS 142 requires the use of projections, estimates and assumptions as to the future performance of the operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections resulting in revisions to our assumptions and, if required, recognizing an impairment loss. Based on our assessment, we do not believe our goodwill is impaired, and we have not recorded a charge from the adoption of SFAS 142 (see Note 11 in the Notes to Consolidated Financial Statements). For each of the years ending December 31, 2007 and 2006, the recorded value of goodwill was $15.5 million.

At December 31, 2007 and 2006, we had $132.3 million and $153.1 million of intangible assets, net of accumulated amortization, respectively, related to natural gas transportation contracts which were recorded as part of our acquisition of Val Verde on June 30, 2002. The value assigned to the natural gas transportation contracts required management to make estimates regarding the fair value of the assets acquired. In connection with the acquisition of Val Verde, we assumed fixed-term gas transportation contracts with customers in the San Juan Basin in New Mexico and Colorado. We assigned $239.6 million of the purchase price to these fixed-term contracts based upon a fair value appraisal at the time of the acquisition. The value assigned to intangible assets is amortized on a unit-of-production basis, based upon the actual throughput of the system compared to the expected total throughput for the lives of the contracts. From time to time, we update throughput estimates and evaluate the remaining expected useful life of the contract assets based upon the best available information. A variance of 10% in our aggregate production estimate for the Val Verde systems would have an approximate $2.4 million impact on annual amortization expense. Changes in the estimated remaining production will impact the timing of amortization expense reported for future periods.

At December 31, 2007, we have $40.2 million of excess investments, net of accumulated amortization, in our equity investments in Centennial, Seaway and Jonah, which are being amortized over periods ranging from 10 to 39 years (see Note 12 in the Notes to Consolidated Financial Statements). The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $26.9 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline. The value assigned to our excess investment in Jonah was created as a result of interest capitalized on the construction of Jonah's expansion. As portions of the expansion are placed into service, we amortize the $7.0 million excess investment in Jonah on a straight-line basis over the life of the assets constructed. A variance of 10% in our amortization expense allocated to equity earnings could have up to an approximate $0.6 million impact on annual earnings.

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Results of Operations

The following table summarizes financial information by business segment for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	For Year Ended December 31,		
	2007	2006	2005
Operating revenues:			
Downstream Segment	$ 362,691	$ 304,301	$ 287,191
Upstream Segment	9,173,683	9,109,629	8,110,239
Midstream Segment (1)	122,235	201,269	211,171
Intersegment eliminations	(549)	(7,714)	(3,567)
Total operating revenues	9,658,060	9,607,485	8,605,034
Operating income:			
Downstream Segment	135,055	91,262	88,143
Upstream Segment	84,222	70,840	33,174
Midstream Segment (1)	25,767	65,499	98,716
Intersegment eliminations	4,511	2,178	—
Total operating income	249,555	229,779	220,033
Equity earnings (losses):			
Downstream Segment	(12,396)	(8,018)	(2,984)
Upstream Segment	2,602	11,905	23,078
Midstream Segment (1)	83,060	35,052	—
Intersegment eliminations	(4,511)	(2,178)	—
Total equity earnings	68,755	36,761	20,094
Earnings before interest: (2)			
Downstream Segment	184,251	84,746	85,914
Upstream Segment	87,246	83,540	56,408
Midstream Segment (1)	109,463	101,219	98,940
Interest expense	(112,253)	(96,852)	(88,620)
Interest capitalized	11,030	10,681	6,759
Income before provision for income taxes	279,737	183,334	159,401
Provision for income taxes	557	652	—
Income from continuing operations	279,180	182,682	159,401
Discontinued operations	—	19,369	3,150
Net income	$ 279,180	$ 202,051	$ 162,551

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise Products Partners, Jonah was deconsolidated and has been subsequently accounted for as an equity investment (see Note 9 in the Notes to Consolidated Financial Statements).

(2) See Note 14 in the Notes to Consolidated Financial Statements for a reconciliation of earnings before interest to net income.

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

Downstream Segment

The following table provides financial information for the Downstream Segment for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	For Year Ended December 31, 2007	2006	2005	Increase (Decrease) 2007-2006	2006-2005
Operating revenues:					
Sales of petroleum products	$ 30,326	$ 5,800	$ —	$ 24,526	$ 5,800
Transportation — Refined products	170,231	152,552	144,552	17,679	8,000
Transportation — LPGs	101,076	89,315	96,297	11,761	(6,982)
Other	61,058	56,634	46,342	4,424	10,292
Total operating revenues	362,691	304,301	287,191	58,390	17,110
Costs and expenses:					
Purchases of petroleum products	30,041	5,526	—	24,515	5,526
Operating expense	103,406	106,455	98,534	(3,049)	7,921
Operating fuel and power	39,906	38,354	32,500	1,552	5,854
General and administrative	16,929	17,085	17,653	(156)	(568)
Depreciation and amortization	46,141	41,405	39,403	4,736	2,002
Taxes — other than income taxes	9,866	8,437	11,097	1,429	(2,660)
Gains on sales of assets	(18,653)	(4,223)	(139)	(14,430)	(4,084)
Total costs and expenses	227,636	213,039	199,048	14,597	13,991
Operating income	135,055	91,262	88,143	43,793	3,119
Gain on sale of ownership interest in MB Storage	59,628	—	—	59,628	—
Equity losses	(12,396)	(8,018)	(2,984)	(4,378)	(5,034)
Interest income	879	1,008	477	(129)	531
Other income — net	1,085	494	278	591	216
Earnings before interest	$ 184,251	$ 84,746	$ 85,914	$ 99,505	$ (1,168)

The following table presents volumes delivered in barrels and average tariff per barrel for the years ended December 31, 2007, 2006 and 2005 (in thousands, except tariff information):

	For Year Ended December 31, 2007	2006	2005	Percentage Increase (Decrease) 2007-2006	2006-2005
Volumes Delivered:					
Refined products	174,910	165,269	160,667	6%	3%
LPGs	41,950	44,997	45,061	(7%)	—
Total	216,860	210,266	205,728	3%	2%
Average Tariff per Barrel:					
Refined products	$ 0.97	$ 0.92	$ 0.90	5%	2%
LPGs	2.41	1.98	2.14	22%	(7%)
Average system tariff per barrel	$ 1.25	$ 1.15	$ 1.17	9%	(2%)

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Effective November 1, 2006, we purchased a refined products terminal in Aberdeen, Mississippi, from Mississippi Terminal and Marketing Inc. At this terminal, we conduct distribution and marketing operations and terminaling services for our throughput and exchange partners. We also purchase petroleum products from our throughput partners that we in turn sell through spot sales at the Aberdeen truck rack to third-party wholesalers and retailers of refined products. For the years ended December 31, 2007 and 2006, sales related to petroleum products marketing activities were $30.3 million and $5.8 million, respectively, and purchases of petroleum products were $30.0 million and $5.5 million, respectively.

Revenues from refined products transportation increased $17.7 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to a 6% increase in the refined products volumes delivered and a 5% increase in the average tariff per barrel. Volume increases were primarily due to increases in motor fuel and distillate revenue due to demand in the Midwest markets resulting from refineries undergoing maintenance. The average tariff per barrel for refined products increased primarily due to increases in system tariffs, which went into effect in February and July 2007, as well as the impact of Centennial on the average rates. Movements during the year ended December 31, 2007 on Centennial were a smaller percentage of the total refined products deliveries when compared to the prior year period. When the proportion of refined products deliveries from a Centennial origin increases, the average TEPPCO tariff declines (even if the actual volume transported on Centennial increases). Conversely, if the proportion of the refined products deliveries from a Centennial origin decrease, TEPPCO's average tariff increases (even if the actual volume transported on Centennial decreases).

Revenues from LPGs transportation increased $11.8 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to a 22% increase in the LPG average tariff per barrel, partially offset by a 7% decrease in the LPG volumes delivered. The increase in the average rate per barrel is a result of decreased short-haul deliveries and increased long-haul deliveries during the year ended December 31, 2007 compared with the year ended December 31, 2006. The decrease in the short-haul volumes delivered is due to the sale of a pipeline on March 1, 2007 to Louis Dreyfus. LPG transportation volumes in 2006 include approximately 9.8 million barrels of short-haul propane movements through this pipeline as compared to 2.2 million barrels during the period from January 1, 2007 through February 28, 2007. This decrease was partially offset by an increase in long-haul deliveries of propane in the Midwest and Northeast market areas primarily as a result of colder than normal weather that extended from January through April of 2007 and lower deliveries of propane in the 2006 period in the Midwest and Northeast market areas as a result of warmer than normal winter weather, high propane prices and scheduled plant maintenance, known as turnarounds.

Other operating revenues increased $4.4 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to a $2.9 million increase in LPG rental, location exchange and tender deduction revenue, a $2.0 million increase in rental and storage revenue from previous asset acquisitions and $1.5 million in increased volumes of product sales, partially offset by $2.6 million of increased costs in upsystem product exchanges.

Costs and expenses increased $14.6 million for the year ended December 31, 2007, compared with the year ended December 31, 2006. Purchases of petroleum products, discussed above, increased $24.5 million, compared with the prior year. Operating expenses decreased $3.0 million primarily due to a $4.9 million decrease in pipeline inspection and repair costs associated with our integrity management program; a $3.4 million increase in product measurement gains; a $2.8 million decrease relating to prior year settlement charges for our retirement cash balance plan (see Note 5 in the Notes to Consolidated Financial Statements); a $2.6 million decrease in operating costs related to the migration to a shared services environment with EPCO, including integrating such departments as engineering and information technology; and a $1.5 million prior year lower of cost or market adjustment on inventory. These decreases in operating expenses were partially offset by a $4.0 million increase in transportation expense related to movements on the Centennial pipeline; a $3.6 million decrease in the prior year in accruals for employee vacations due to the migration to a shared services environment with EPCO; a $3.6 million increase in pipeline operating costs as a result of timing of projects in the current year; and a $1.1 million increase in environmental assessment and remediation costs. Operating fuel and power increased $1.6 million primarily due to increased mainline throughput and higher power rates as a result of the increased cost of fuel. General and administrative expenses decreased $0.2 million primarily due to $1.9 million of severance expense in the prior year resulting from the migration to a shared services environment with EPCO, partially offset by a $1.0 million increase in office rental expenses and a $0.6 million increase in labor and benefits expense. Depreciation expense increased $4.7 million primarily due to assets placed into service, asset retirements in 2006 and 2007 and an acceleration of depreciation expense related to the decommissioning of a pipeline segment in 2007. Taxes — other than income taxes increased $1.4 million primarily due to a higher property asset base in the 2007 period and true-ups of property tax accruals. During the year ended December 31, 2007, we recognized net gains of $18.7 million from the sales of various assets in the Downstream Segment to Enterprise Products Partners and Louis Dreyfus, compared with $4.2 million of net gains in 2006 (see Note 10 in the Notes to Consolidated Financial Statements).

Net losses from equity investments increased for the year ended December 31, 2007, compared with the year ended December 31, 2006, as shown below (in thousands):

	For Year Ended December 31, 2007	For Year Ended December 31, 2006	Increase (Decrease)
Centennial	$ (13,528)	$ (17,094)	$ 3,566
MB Storage	1,089	9,082	(7,993)
Other	43	(6)	49
Total equity losses	$ (12,396)	$ (8,018)	$ (4,378)

Equity losses in Centennial decreased $3.6 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to higher transportation revenues and volumes resulting from colder than normal winter weather in the Northeast, partially offset by higher amortization expense on the portion of TE Products' excess investment in Centennial. Equity earnings from MB Storage decreased $8.0 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, due to the sale of MB Storage on March 1, 2007 to Louis Dreyfus. For the 2007 and 2006 periods, TE Products' sharing ratios in the earnings of MB Storage were approximately 67.7% and 59.4%, respectively.

On March 1, 2007, TE Products sold its 49.5% ownership interest in MB Storage and its 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage) to Louis Dreyfus for approximately $137.3 million in cash (see Note 10 in the Notes to Consolidated Financial Statements). We recognized a gain of approximately $59.6 million related to the sale of our equity interests, which is included in gain on sale of ownership interest in MB Storage in our statements of consolidated income.

Other income — net increased $0.6 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, due to the receipt of various right-of-way payments in 2007.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

For the period ended December 31, 2006, sales related to refined products marketing activities were $5.8 million and purchases of refined products for these activities were $5.5 million.

Revenues from refined products transportation increased $8.0 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to minor increases in refined products volumes transported and the refined products average rate per barrel. Volume increases were primarily due to increased demand for products supplied from the U.S. Gulf Coast into Midwest markets resulting from higher distillate price differentials and a greater demand for gasoline blendstocks, partially offset by unfavorable differentials for motor fuels during the first quarter of 2006. Additionally, refined products revenues increased due to increased terminaling activity at truck racks, including at our Shreveport terminal, which was placed in service in 2005, and higher product storage fees. The average tariff increased primarily due to an increase in gasoline blendstock deliveries, which have a higher tariff, and an increase in system tariffs, which went into effect in April and July 2006. The increase in the refined products average tariff rate was partially offset by the impact of Centennial on the average rates.

Revenues from LPGs transportation decreased $7.0 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to lower deliveries of propane in the upper Midwest and Northeast market areas as a result of warmer than normal winter weather in the first and fourth quarters of 2006, high propane prices and plant turnarounds. Butane deliveries were below prior year levels due to a refinery turnaround during the fourth quarter of 2006. The LPGs average rate per barrel decreased from the prior year period primarily as a result of increased short-haul deliveries during the year ended December 31, 2006, compared with the year ended December 31, 2005.

Other operating revenues increased $10.3 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to a $5.3 million increase from increased storage revenue on assets acquired in July 2005 and an increase of $1.9 million in other system storage, a
$2.1 million increase in

refined products tender deduction revenues, additives and custody transfers fees, a $0.7 million increase in refined products loading fees and $0.4 million of higher RGP revenues on the northern portion of our Dean Pipeline.

Costs and expenses increased $13.9 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Purchases of petroleum products, discussed above, increased $5.5 million, compared with the prior year. Operating expenses increased $7.9 million primarily due to a $5.8 million increase in pipeline operating costs primarily as a result of acquisitions made in 2005; a $3.5 million increase in product measurement losses; $2.8 million in settlement charges related to the termination of our retirement cash balance plan (see Note 5 in the Notes to Consolidated Financial Statements); $2.1 million of higher insurance premiums; a $1.5 million lower of cost or market adjustment on inventory; $0.8 million of expenses relating to our special unitholder meeting; a $0.7 million increase in rental expense on a lease with a third-party pipeline and $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO. These increases in costs and expenses were partially offset by a $3.4 million decrease in pipeline inspection and repair costs associated with our integrity management program, a $1.8 million decrease in accruals for employee vacations due to a change in the vacation policy in 2006 as a result of the migration to a shared services environment with EPCO; a $1.6 million decrease in labor and benefits expense primarily associated with incentive compensation plan vestings in the prior year; a $1.1 million decrease due to regulatory penalties for past incidents; $0.6 million favorable insurance settlement for prior insurance claims; and $0.6 million decrease in accruals related to post employment liabilities associated with DCP. Operating fuel and power increased $5.9 million primarily due to increased mainline throughput and higher power rates. General and administrative expenses decreased $0.6 million primarily due to a $1.5 million decrease in labor and benefits expense associated with prior year vesting provisions in our incentive compensation plans and decrease in accruals for employee vacations and $0.9 million in transition costs in the 2005 period due to the change in ownership of our General Partner, partially offset by a $1.1 million increase relating to the retirement of an executive in February 2006 and $0.7 million in severance expense as a result of the migration to a shared services environment with EPCO and higher executive compensation expense. Depreciation expense increased $2.0 million primarily due to assets placed into service, asset retirements in 2006 and the recording of a conditional asset retirement obligation as discussed below. Taxes — other than income taxes decreased $2.7 million primarily due to a true-up of property tax accruals for prior tax years and higher payroll taxes in the prior year period. During the years ended December 31, 2006 and 2005, we recognized net gains of $4.2 million and $0.1 million, respectively, from the sales of various assets in the Downstream Segment.

During 2006, we recorded $0.3 million of expense, included in depreciation and amortization expense, related to a conditional asset retirement obligation, and we recorded a $0.5 million liability, which represents the fair value of the conditional asset retirement obligation related to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination (see Note 8 in the Notes to Consolidated Financial Statements).

Net losses from equity investments increased for the year ended December 31, 2006, compared with the year ended December 31, 2005, as shown below (in thousands):

	For Year Ended December 31, 2006	For Year Ended December 31, 2005	Increase (Decrease)
Centennial	$ (17,094)	$ (10,727)	$ (6,367)
MB Storage	9,082	7,715	1,367
Other	(6)	28	(34)
Total equity losses	$ (8,018)	$ (2,984)	$ (5,034)

Equity losses in Centennial increased $6.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to lower transportation volumes and increased costs relating to pipeline inspection and repair costs associated with its integrity management program, partially offset by lower amortization expense on the portion of TE Products' excess investment in Centennial. Equity earnings in MB Storage increased $1.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to lower product measurement losses on the MB Storage system and higher revenues, partially offset by higher system maintenance expenses and higher operating fuel and power resulting from higher power rates and increased volumes. For the years ended December 31, 2006 and 2005, TE Products' sharing ratios in the earnings of MB Storage were approximately 59.4% and 64.2%, respectively.

Interest income increased $0.5 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher interest income earned on cash investments and other investing activities.

Upstream Segment

The following table provides financial information for the Upstream Segment for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2007	2006	2005	2007-2006	2006-2005
Operating revenues: (1)					
Sales of petroleum products (2) (3)	$ 9,117,327	$ 9,060,782	$ 8,062,131	$ 56,545	$ 998,651
Transportation — Crude oil	45,952	38,822	37,614	7,130	1,208
Other	10,404	10,025	10,494	379	(469)
Total operating revenues	9,173,683	9,109,629	8,110,239	64,054	999,390
Costs and expenses: (1)					
Purchases of petroleum products (2) (3)	8,992,048	8,953,407	7,989,682	38,641	963,725
Operating expense	58,976	54,422	52,808	4,554	1,614
Operating fuel and power	7,001	6,989	5,122	12	1,867
General and administrative	7,619	5,986	7,077	1,633	(1,091)
Depreciation and amortization	18,257	14,400	17,161	3,857	(2,761)
Taxes — other than income taxes	5,560	5,390	5,333	170	57
Gains on sales of assets	—	(1,805)	(118)	1,805	(1,687)
Total costs and expenses	9,089,461	9,038,789	8,077,065	50,672	961,724
Operating income	84,222	70,840	33,174	13,382	37,666
Equity earnings	2,602	11,905	23,078	(9,303)	(11,173)
Interest income	161	407	—	(246)	407
Other income — net	261	388	156	(127)	232
Earnings before interest	$ 87,246	$ 83,540	$ 56,408	$ 3,706	$ 27,132

(1) Amounts in this table are presented after elimination of intercompany transactions, including sales and purchases of petroleum products.

(2) Petroleum products includes crude oil, lubrication oils and specialty chemicals.

(3) On April 1, 2006, we adopted Emerging Issues Task Force ("EITF") 04-13. Amounts for the period from April 1, 2006 through December 31, 2006 have been fully adjusted for the impact of adopting EITF 04-13. The period from January 1, 2006 through March 31, 2006 and the 2005 period have not been adjusted for the adoption of EITF 04-13, as retroactive restatement was not permitted, which impacts comparability (for further discussion, see below).

Information presented in the following table includes the margin of the Upstream Segment, which may be viewed as a non-GAAP (Generally Accepted Accounting Principles) financial measure under the rules of the SEC. We calculate the margin of the Upstream Segment as revenues generated from the sale of crude oil and lubrication oil, and transportation of crude oil, less the costs of purchases of crude oil and lubrication oil, in each case, prior to the elimination of intercompany sales, revenues and purchases between wholly-owned subsidiaries. We believe that margin is a more meaningful measure of financial performance than sales and purchases of crude oil and lubrication oil due to the significant fluctuations in sales and purchases caused by variations in the volumes marketed and prices for products marketed. Additionally, we use margin internally to evaluate the financial performance of the Upstream Segment because it excludes expenses that are not directly related to the marketing and sales activities being evaluated. Margin and volume information for the years ended December 31, 2007, 2006 and 2005 is presented below (in thousands, except per barrel and per gallon amounts):

	For Year Ended December 31, 2007	2006	2005	Percentage Increase (Decrease) 2007-2006	2006-2005
Margins: (1)					
Crude oil marketing	$ 72,655	$ 58,358	$ 30,597	24%	91%
Lubrication oil sales	8,820	8,565	7,455	3%	15%
Revenues: (1)					
Crude oil transportation	75,285	67,439	61,611	12%	9%
Crude oil terminaling	14,471	11,835	10,400	22%	14%
Total margin/revenues	$ 171,231	$ 146,197	$ 110,063	17%	33%
Total barrels/gallons:					
Crude oil marketing (barrels) (1)	232,041	222,069	203,325	4%	9%
Lubrication oil volume (gallons)	15,344	14,444	14,844	6%	(3%)
Crude oil transportation (barrels)	96,451	91,487	94,743	5%	(3%)
Crude oil terminaling (barrels)	135,010	125,974	110,254	7%	14%
Margin per barrel or gallon:					
Crude oil marketing (per barrel) (1)	$ 0.313	$ 0.263	$ 0.150	19%	75%
Lubrication oil margin (per gallon)	0.575	0.593	0.502	(3%)	18%
Average tariff per barrel:					
Crude oil transportation	$ 0.781	$ 0.737	$ 0.650	6%	13%
Crude oil terminaling	0.107	0.094	0.094	14%	—

(1) Amounts in this table are presented prior to the eliminations of intercompany sales, revenues and purchases between TCO and TCPL, both of which are our wholly-owned subsidiaries. TCO is a significant shipper on TCPL. Crude oil marketing volumes also include inter-region transfers, which are transfers among TCO's various geographically managed regions.

The following table reconciles the Upstream Segment margin to operating income using the information presented in the statements of consolidated income and the Upstream Segment financial information on the preceding page (in thousands):

	For Year Ended December 31, 2007	2006	2005
Sales of petroleum products	$ 9,117,327	$ 9,060,782	$ 8,062,131
Transportation — Crude oil	45,952	38,822	37,614
Less: Purchases of petroleum products	(8,992,048)	(8,953,407)	(7,989,682)
Total margin/revenues	171,231	146,197	110,063
Other operating revenues	10,404	10,025	10,494
Net operating revenues	181,635	156,222	120,557
Operating expense	58,976	54,422	52,808
Operating fuel and power	7,001	6,989	5,122
General and administrative expense	7,619	5,986	7,077
Depreciation and amortization	18,257	14,400	17,161
Taxes — other than income taxes	5,560	5,390	5,333
Gains on sales of assets	—	(1,805)	(118)
Operating income	$ 84,222	$ 70,840	$ 33,174

On April 1, 2006, we adopted EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our statements of consolidated income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of consolidated income. Implementation of EITF 04-13 reduced revenues and purchases of petroleum products on our statements of consolidated income by approximately $2,743.6 million for the year ended December 31, 2007 and $1,127.6 million for the period from April 1, 2006 through December 31, 2006. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our statements of consolidated income for the period from January 1, 2006 through March 31, 2006 and for the year ended December 31, 2005 are approximately $275.4 million and $1,405.7 million, respectively. Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted, which affects comparability with periods in which EITF 04-13 has been implemented.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Sales of petroleum products and purchases of petroleum products increased $56.6 million and $38.6 million, respectively, for the year ended December 31, 2007, compared with the year ended December 31, 2006. Operating income increased $13.4 million for the year ended December 31, 2007, compared with the year ended December 31, 2006. The increases in sales and purchases were primarily a result of increased volumes marketed and increases in the price of crude oil, partially offset by the effects of the adoption of EITF 04-13, which reduced each of revenues and purchases of petroleum products by $2,743.6 million for the 2007 period as compared with $1,127.6 million for the 2006 period. The average NYMEX price of crude oil was $72.24 per barrel for the year ended December 31, 2007, compared with $66.23 per barrel for the year ended December 31, 2006. Favorable market conditions and increased volumes transported and marketed, partially offset by increased costs and expenses discussed below, were the primary factors resulting in an increase in operating income. Crude oil marketing margin increased $14.3 million (approximately $2.7 million of which is attributable to intercompany transactions between TCO and TCPL), primarily due to favorable market conditions and increased volumes marketed, partially offset by increased transportation costs. Crude oil transportation revenues (prior to intercompany eliminations) increased $7.8 million primarily due to tariff increases in the third quarter of 2006 on the South Texas, West Texas and Red River systems, increased transportation revenues and volumes on our Red River and Basin systems related to movements on higher tariff segments and increased transportation volumes and revenues on our West Texas systems related to the completion of organic growth projects. Crude oil terminaling revenues increased $2.6 million as a result of increased pumpover volumes at Cushing, Oklahoma, due to crude oil market conditions and the completion of organic growth projects at Cushing, partially offset by decreased pumpover volumes at Midland, Texas. Lubrication oil sales margin increased $0.3 million primarily due to increased volumes of lower margin lubrication oils, which also resulted in a lower average margin per gallon on sales of lubrication oils.

Other operating revenues increased $0.4 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to higher revenues from documentation and other services to support customers’ trading activity at Midland and Cushing.

Costs and expenses increased $50.7 million for the year ended December 31, 2007, compared with the year ended December 31, 2006. Purchases of petroleum products, discussed above, increased $38.6 million, compared with the prior year. Operating expenses increased $4.6 million primarily due to a $3.1 million increase in pipeline operating and maintenance expense, a $2.8 million increase in operating costs related to shared services with EPCO, a $1.7 million increase in labor and benefits expense associated with our incentive compensation plans and other labor expense, a $1.4 million decrease in the 2006 period in accruals for employee vacations due to the migration to a shared services environment with EPCO, a $0.8 million favorable insurance settlement in the 2006 period and a $0.7 million increase in environmental assessment and remediation costs, partially offset by a $3.3 million increase in product measurement gains, a $1.2 million decrease in insurance premiums, a $1.0 million decrease in pipeline repair and maintenance expense associated with our integrity management program and $0.4 million of severance expense in the 2006 period as a result of the migration to a shared services environment with EPCO. Operating fuel and power remained virtually unchanged between periods. General and administrative expenses increased $1.6 million primarily due to a $1.2 million increase in labor and benefits expense and a $0.4 million increase in general and administrative consulting services and supplies and expenses. Depreciation and amortization expense increased $3.9 million primarily due to assets placed in service in 2006. Taxes — other than income taxes increased $0.2 million due to true-ups of property tax accruals. During the year ended December 31, 2006, we recognized a gain of $1.8 million primarily on the sale of idled crude pipeline assets to Enterprise Products Partners (see Note 10 in the Notes to Consolidated Financial Statements).

Equity earnings from our investment in Seaway decreased $9.3 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to the decrease in the sharing ratio from 47% to 40% (see Note 9 in the Notes to Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to lower transportation volumes, which were negatively impacted by the unexpected temporary shutdown of several regional refineries for maintenance and repairs, pipeline capacity constraints for crude oil transportation downstream of the Cushing trading hub, increased volumes of Canadian crude oil in the United States and logistics changes at key refineries to accommodate heavier crude oil. Long-haul volumes on Seaway averaged 135,000 barrels per day during the year ended December 31, 2007, compared with 242,000 barrels per day during the year ended December 31, 2006. These decreases were partially offset by higher expenses in the 2006 period related to pipeline integrity costs for corrective measures taken for the pipeline release in May 2005, increased environmental remediation and assessment costs, higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates.

After a release occurred on the Seaway pipeline in May 2005, the maximum operating pressure on the pipeline system was reduced by 20% until the cause of the failure was determined. Corrective measures were implemented upon the release in 2005 and were completed during the second quarter of 2006. Seaway operated at reduced maximum pressure through May 2006. On June 1, 2006, Seaway's operating pressure was increased to 100%. As a result of operating at reduced maximum pressure, we used a drag reducing agent to increase the flow of product through the pipeline system during the period when operating pressures were reduced. The drag reducing agent allowed us to maintain the higher volumes transported, but also increased our operating costs. The reduced pressure did not have a material adverse effect on our financial position, results of operations or cash flows (see Note 17 in the Notes to Consolidated Financial Statements).

Interest income decreased $0.3 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, due to lower interest income earned on cash investments and other investing activities.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Sales of petroleum products and purchases of petroleum products increased $998.7 million and $963.7 million, respectively, for the year ended December 31, 2006, compared with the year ended December 31, 2005. Operating income increased $37.7 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. The increases in sales and purchases were primarily a result of an increase in the price of crude oil and increased volumes marketed, partially offset by the effect of the adoption of EITF 04-13, which reduced each of revenues and purchases of petroleum products by $1,127.6 million for the period from April 1, 2006 through December 31, 2006. The average NYMEX price of crude oil was $66.23 per barrel for the year ended December 31, 2006, compared with $56.65 per barrel for the year ended December 31, 2005. The increase in the average price of crude oil, partially offset by increased purchases and costs and expenses discussed below, were the primary factors resulting in an increase in operating income. Crude oil marketing margin increased $27.8 million (approximately $4.9 million of which is attributable to intercompany transactions between TCO and TCPL) primarily due to favorable market conditions and increased volumes marketed, partially offset by increased transportation costs. Crude oil transportation revenues (prior to intercompany eliminations) increased $5.8 million primarily due to higher revenues on our Red River and West Texas systems related to movements on higher tariff segments and revenues from acquisitions in 2005 and increased transportation volumes and revenues on our South Texas system, partially offset by decreases in transportation volumes on lower tariff segments of our Basin and Red River systems. Crude oil terminaling revenues increased $1.4 million as a result of increased pumpover volumes at Midland and Cushing. Lubrication oil sales margin increased $1.1 million due to an increase in sales of fuel and lubrication oil volumes that have a higher average margin per gallon than in the prior year period, partially offset by a decrease in other sales volumes.

Other operating revenues decreased $0.5 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to a $1.5 million favorable settlement of inventory imbalances in the first quarter of 2005, partially offset by higher revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses increased $961.7 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Purchases of petroleum products, discussed above, increased $963.7 million, compared with the prior year. Operating expenses increased $1.6 million from the prior year period, primarily due to a $1.5 million increase in environmental assessment and remediation costs, $1.5 million of higher insurance premiums, a $0.9 million increase as a result of product measurement losses and higher crude oil prices, a $0.9 million increase in pipeline operating and maintenance expenses, $0.6 million in settlement charges related to the termination of our retirement cash balance plan (see Note 5 in the Notes to Consolidated Financial Statements) and $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO. These increases in operating expenses were partially offset by a $1.4 million decrease in accruals for employee vacations due to the migration to a shared services environment with EPCO, a $1.1 million decrease in labor and benefits expense related to vesting provisions in certain of our compensation plans in the prior year period as a result of the change in ownership of our General Partner, a $0.8 million favorable insurance settlement, a $0.5 million decrease in costs associated with our integrity management program and a $0.4 million decrease in expense related to adjustments to the workers compensation accrual. Operating fuel and power increased $1.9 million primarily as a result of increased power rates in the 2006 period, partially offset by lower transportation volumes. General and administrative expenses decreased $1.1 million from the prior year primarily due to a $1.4 million decrease in labor and benefits expense as a result of higher labor and benefits costs in the prior year associated with vesting provisions in certain of our incentive compensation plans and the change in ownership of our General Partner, which resulted in higher incentive compensation expenses for that period and a $0.5 million decrease in accruals for employee vacations due to a change in the vacation policy in 2006 as a result of the migration to a shared services environment with EPCO, partially offset by $0.4 million in severance expense as a result of the migration to a shared services environment with EPCO and $0.3 million in settlement charges related to the termination of our retirement cash balance plan. Depreciation and amortization expense decreased $2.8 million primarily due to $2.6 million of asset impairments and asset retirements during the prior year. Taxes — other than income taxes increased $0.1 million due to increases in property tax accruals and a higher property asset base in 2006. During the year ended December 31, 2006, we recognized a gain of $1.8 million primarily on the sale of idled crude pipeline assets to Enterprise Products Partners (see Note 10 in the Notes to Consolidated Financial Statements).

Equity earnings from our investment in Seaway decreased $11.2 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Our sharing ratio for 2005 was 60%, while for the full year of 2006, it was 47% of the revenue and expense of Seaway (see Note 9 in the Notes to Consolidated Financial Statements). Equity earnings from our investment in Seaway also decreased due to higher operating, general and administrative expenses related to pipeline integrity costs for the corrective measures taken for the pipeline release in May 2005, increased environmental remediation and assessment costs, higher operating fuel and power costs relating to the use of a drag reducing agent and higher power rates, a favorable settlement in the first quarter of 2005 with a former owner of Seaway’s crude oil assets regarding inventory imbalances that were not acquired by us and decreased transportation volumes. Long-haul volumes on Seaway averaged 242,000 barrels per day during the year ended December 31, 2006, compared with 271,000 barrels per day during the year ended December 31, 2005. Fourth quarter 2005 long-haul transportation volumes were higher due in part to Hurricane Katrina, which affected the U.S. Gulf Coast in 2005.

Interest income increased $0.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher interest income earned on cash investments and other investing activities.

Midstream Segment

The following table provides financial information for the Midstream Segment for the years ended December 31, 2007, 2006 and 2005 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2007	2006	2005	2007-2006	2006-2005
Operating revenues: (1)					
Sales of petroleum products (2)	$ —	$ 18,766	$ —	$ (18,766)	$ 18,766
Gathering — Natural gas	61,634	123,933	152,797	(62,299)	(28,864)
Transportation — NGLs (3)	46,542	43,838	43,915	2,704	(77)
Other	14,059	14,732	14,459	(673)	273
Total operating revenues	122,235	201,269	211,171	(79,034)	(9,902)
Costs and expenses: (1)					
Purchases of petroleum products	—	17,272	—	(17,272)	17,272
Operating expense	29,395	42,887	34,758	(13,492)	8,129
Operating fuel and power	14,551	12,107	11,350	2,444	757
General and administrative expense	9,109	8,277	8,413	832	(136)
Depreciation and amortization	40,827	52,447	54,165	(11,620)	(1,718)
Taxes — other than income taxes	2,586	4,156	4,180	(1,570)	(24)
Gains on sales of assets	—	(1,376)	(411)	1,376	(965)
Total costs and expenses	96,468	135,770	112,455	(39,302)	23,315
Operating income	25,767	65,499	98,716	(39,732)	(33,217)
Equity earnings (1)	83,060	35,052	—	48,008	35,052
Interest income	636	662	210	(26)	452
Other income — net	—	6	14	(6)	(8)
Earnings before interest	$ 109,463	$ 101,219	$ 98,940	$ 8,244	$ 2,279

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise Products Partners, Jonah was deconsolidated and operating results, including revenues and costs and expenses, after August 1, 2006 are included in equity earnings (see Note 9 in the Notes to Consolidated Financial Statements).

(2) The 2006 period includes Jonah's natural gas sales to Enterprise Products Partners of $2.9 million through July 31, 2006.

(3) Includes transportation revenue from Enterprise Products Partners of $13.2 million, $10.2 million and $7.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The following table presents volume and average rate information for the years ended December 31, 2007, 2006 and 2005 (in thousands, except average fee and average rate amounts and as otherwise indicated):

	For Year Ended December 31,			Percentage Increase (Decrease)	
	2007	2006	2005	2007-2006	2006-2005
Gathering — Natural Gas — Jonah: (1) (2)					
MMcf	587,354	473,909	415,181	24%	14%
BBtu	647,890	522,667	458,159	24%	14%
Average fee per MMcf	$ 0.236	$ 0.224	$ 0.208	5%	8%
Average fee per MMBtu	$ 0.214	$ 0.204	$ 0.188	5%	8%
Gathering — Natural Gas — Val Verde: (2)					
MMcf	175,667	181,928	180,699	(3%)	1%
BBtu	155,982	160,929	159,398	(3%)	1%
Average fee per MMcf	$ 0.351	$ 0.359	$ 0.369	(2%)	(3%)
Average fee per MMBtu	$ 0.395	$ 0.406	$ 0.418	(3%)	(3%)
Transportation and movements — NGLs:					
Transportation barrels	64,199	63,396	60,486	1%	5%
Lease barrels (3)	12,797	6,350	565	102%	1,024%
Average rate per barrel	$ 0.688	$ 0.674	$ 0.724	2%	(7%)
Natural Gas Sales: (1)					
BBtu	14,774	10,206	—	45%	—
Average fee per MMBtu	$ 4.278	$ 4.984	$ —	(14%)	—
Fractionation — NGLs:					
Barrels	4,175	4,406	4,431	(5%)	(1%)
Average rate per barrel	$ 1.768	$ 1.662	$ 1.747	6%	(5%)
Sales — Condensate: (1) (4)					
Barrels	89.7	74.2	62.1	21%	19%
Average rate per barrel	$ 59.57	$ 62.26	$ 52.21	(4%)	19%

(1) Effective August 1, 2006, with the formation of a joint venture with Enterprise Products Partners, Jonah was deconsolidated and operating results after August 1, 2006 are included in equity earnings (see Note 9 in the Notes to Consolidated Financial Statements). However, this table includes Jonah's volume and average rate information for the full years ended December 31, 2007, 2006 and 2005.

(2) The majority of volumes in Val Verde's contracts are measured in MMcf, while the majority of volumes in Jonah's contracts are measured in MMBtu. Both measures are shown for each asset for comparability purposes.

(3) Revenues associated with capacity leases are classified as other operating revenues in our statements of consolidated income.

(4) All of Jonah's condensate volumes are sold to TCO.

Through July 31, 2006, Jonah's operating results were fully consolidated in the Midstream Segment operating results. Effective August 1, 2006, with the formation of a joint venture with Enterprise Products Partners, Jonah was deconsolidated and has been subsequently accounted for as an equity investment. Operating results for Jonah for the year ended December 31, 2007 and for the period from August 1, 2006 through December 31, 2006 are reported as equity earnings. At December 31, 2007, our ownership interest in Jonah was approximately 80.64% (see Note 9 in the Notes to Consolidated Financial Statements).

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

For the 2006 period, sales of petroleum products relating to natural gas marketing activities were $18.8 million and purchases of petroleum products were $17.3 million. As a service to certain small producers, in late 2005, we began to aggregate purchases of petroleum products, consisting of wellhead gas on Jonah, and re-sell the aggregated quantities at key Jonah delivery points in order to facilitate throughput on Jonah. The purchases and sales were generally contracted to occur in the same calendar month to minimize price risk. During the second quarter of 2006, gas purchase and sales contracts were finalized and executed and the marketing of gas on the Jonah system began. Effective August 1, 2006, with the deconsolidation of Jonah, sales and purchases of petroleum products are reported in equity earnings.

Revenues from the gathering of natural gas decreased $62.3 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to a decrease of $58.6 million resulting from the deconsolidation of Jonah on August 1, 2006. Natural gas gathering revenues from the Val Verde system decreased $3.7 million and volumes gathered decreased 6.3 Bcf for the year ended December 31, 2007 compared to the prior year, primarily due to winter weather production issues during the first quarter of 2007 and the natural decline of coal bed methane production in the fields in which the Val Verde gathering system operates, partially offset by higher volumes from a third party natural gas gathering system connected to Val Verde. Val Verde's average natural gas gathering fee per MMcf decreased 2% primarily due to higher volumes from a third party natural gas connection that has lower rates and lower gathering volumes, partially offset by annual rate escalations. For the year ended December 31, 2007, Val Verde's gathering volumes averaged 481 MMcf per day, compared with 498 MMcf per day for the year ended December 31, 2006.

Revenues from the transportation of NGLs increased $2.7 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to increased volumes transported on the Chaparral and Dean Pipelines and an increase in the average rate on the Chaparral and Dean Pipelines. These increases were partially offset by decreased volumes and a decrease in the average rate on the Panola Pipeline and a 1.6 million barrel decrease in volumes resulting from taking the Wilcox Pipeline out of service in December 2006.

Other operating revenues decreased $0.7 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to a $3.4 million decrease resulting from the deconsolidation of Jonah on August 1, 2006, partially offset by a $2.6 million increase on the Panola Pipeline primarily due to increased revenues and volumes from a pipeline capacity lease. The average rate per barrel for the fractionation of NGLs increased 6% primarily due to the rate structure in the agreement. Under the agreement with the customer, lower volumes of NGLs are fractionated at higher rates.

Costs and expenses decreased $39.3 million for the year ended December 31, 2007, compared with the year ended December 31, 2006. Purchases of petroleum products, discussed above, decreased $17.3 million, compared with the prior year. Operating expenses decreased $13.5 million primarily due to a $7.8 million decrease resulting from the deconsolidation of Jonah on August 1, 2006, $3.6 million of favorable product measurement gains on our pipelines and gathering system, a $2.0 million decrease in other operating expenses and allocated shared service costs (including labor, benefits, rent and other supplies and expenses) related to the share services environment with EPCO, $1.8 million of expense in the 2006 period associated with the formation of the Jonah joint venture with Enterprise Products Partners and costs related to the 2006 special unitholder meeting, $1.0 million of favorable imbalance valuations primarily on Val Verde and a $0.7 million decrease in insurance premiums, partially offset by a $1.9 million increase in pipeline inspection and repair costs associated with our integrity management program and $1.4 million of higher costs on Val Verde related to the timing of project costs and pipeline maintenance. Operating fuel and power increased $2.5 million primarily due to higher fuel costs and increased transportation volumes on Chaparral. General and administrative expenses increased $0.8 million due to higher labor and benefits expense and higher professional services costs, partially offset by higher transition costs in the 2006 period from the migration to a shared services environment with EPCO. Depreciation and amortization expense decreased $11.6 million primarily due to the deconsolidation of Jonah. Taxes — other than income taxes decreased $1.6 million primarily due to the deconsolidation of Jonah and true-ups of property tax accruals. During the year ended December 31, 2006, gains of $1.4 million were recognized on the sales of various equipment at Val Verde.

Increased equity earnings of $48.0 million for the year ended December 31, 2007 were generated from our ownership interest in Jonah. At December 31, 2007, our interest in Jonah was 80.64%, compared with 99.7% in the prior year period, as a result of reaching certain milestones in 2007 (as described in the partnership agreement) in the construction of the Phase V expansion (see Note 9 in the Notes to Consolidated Financial Statements and Items 1 & 2. Business and Properties, Midstream Segment — Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs — Jonah Gas Gathering Joint Venture). Jonah's income from continuing operations for the year ended December 31, 2007 increased $23.1 million, compared with the prior year, primarily due to increased revenues and volumes generated from the completion of Phase IV of the Jonah expansion project in February 2006 and increased revenues and volumes generated from the completion of a portion of Phase V of the expansion project in the fourth quarter of 2006 and in July 2007, partially offset by increased operating costs and depreciation and amortization expense relating to these expansions.

For the year ended December 31, 2007, Jonah's gathering volumes averaged approximately 1.6 Bcf per day, compared with approximately 1.3 Bcf per day for the year ended December 31, 2006. Jonah's volumes gathered increased 113.4 Bcf for the year ended December 31, 2007, primarily as a result of completion of the Phase IV expansion and partial completion of the Phase V expansion, compared with the year ended December 31, 2006. Jonah's average fee per MMcf increased 5% for the year ended December 31, 2007 compared with the prior year primarily due to lower system wellhead pressures during the 2007 period as a result of the Phase V expansion. Jonah's condensate sales volumes increased 21% for the year ended December 31, 2007 compared with the prior year, primarily due to the increase in gathering volumes. The decreases in Jonah's natural gas sales average fee per MMcf and average condensate rate per barrel for the year ended December 31, 2007, were primarily a result of lower market prices compared with the year ended December 31, 2006.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

For the 2006 period, sales of petroleum products relating to natural gas marketing activities were $18.8 million and purchases of petroleum products were $17.3 million. Effective August 1, 2006, with the deconsolidation of Jonah, sales and purchases of petroleum products are reported in equity earnings.

Revenues from the gathering of natural gas decreased $28.9 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Natural gas gathering revenues from the Jonah system decreased $37.9 million due to the deconsolidation of Jonah on August 1, 2006, partially offset by an increase of $10.4 million primarily due to the Phase IV expansion of the Jonah system completed in February 2006, prior to deconsolidation. Natural gas gathering revenues from the Val Verde system decreased $1.4 million for the year ended December 31, 2006, primarily due to the natural decline of coal bed methane production in the fields in which the Val Verde gathering system operates. For the year ended December 31, 2006, Val Verde's gathering volumes averaged 498 MMcf per day, compared with 495 MMcf per day for the year ended December 31, 2005. Val Verde's volumes gathered increased 1.2 Bcf primarily due to increased volumes from a natural gas connection that occurred in December 2004 on the Val Verde system. Val Verde's average natural gas gathering rate per MMcf decreased 3% primarily due to newer contracts that have lower rates than the previous year's average rates on Val Verde.

Revenues from the transportation of NGLs decreased $0.1 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to a decrease in the average NGL transportation rate per barrel as a result of increased short-haul movements on the Chaparral Pipeline and a lower average rate per barrel on the Panola Pipeline. During the 2006 period, volumes of NGLs transported increased due to increases on the Chaparral, Panola and Dean Pipelines, partially offset by decreased volumes transported on the Wilcox and San Jacinto Pipelines.

Other operating revenues increased $0.3 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Other operating revenues increased $1.7 million on the Panola Pipeline and $1.2 million on the Chaparral Pipeline primarily due to new pipeline capacity leases. Other operating revenues on Jonah decreased $1.5 million due to the deconsolidation of Jonah on August 1, 2006, partially offset by an increase of $0.6 million due to higher condensate sales. These increases were partially offset by a $1.3 million decrease in Val Verde's other operating revenue as a result of contractual producer minimum fuel levels exceeding actual operating fuel usage. Val Verde retains a portion of its producers' gas to compensate for fuel used in operations. The actual usage of gas can differ from the amount contractually retained from producers. Value retained from producers or sales generated as a result of efficient fuel usage are recognized as other operating revenues. Other operating revenues also decreased $0.4 million due to a decrease in fractionation revenues due to lower volumes during the 2006 period.

Costs and expenses increased $23.3 million for the year ended December 31, 2006, compared with the year ended December 31, 2005. Purchases of petroleum products, discussed above, increased $17.3 million, compared with the prior year. Operating expenses increased $8.1 million primarily due to a $4.3 million increase related to imbalance valuations on Val Verde and Chaparral, a $4.3 million increase in expense as a result of the migration to a shared services environment with EPCO, a $1.4 million increase in expense associated with the formation of the joint venture with Enterprise Products Partners and costs related to the special unitholder meeting and a $1.2 million increase in other pipeline operating and maintenance expense, partially offset by a $3.0 million decrease due to the deconsolidation of Jonah on August 1, 2006. Operating fuel and power increased $0.8 million primarily due to higher transportation volumes and power rates. General and administrative expenses decreased $0.2 million primarily due to lower transition and finance costs from the prior year, partially offset by an increase of $0.6 million in severance expense as a result of the migration to a shared services environment with EPCO and higher legal costs. Depreciation and amortization expense decreased $1.7 million primarily due to a $3.6 million decrease in amortization expense and a $1.2 million decrease in depreciation expense from the deconsolidation of Jonah, partially offset by a $2.2 million increase in amortization expense on Val Verde as a result of a decrease in the estimated life of intangible assets under the units-of-production method and a $0.7 million increase on Val Verde due to accretion expense on conditional asset retirement obligations (as discussed below). During the years ended December 31, 2006 and 2005, gains of $1.4 million and $0.4 million, respectively, were recognized on the sales of various equipment at Val Verde.

During 2006, we recorded $0.3 million of expense included in depreciation and amortization expense, related to conditional asset retirement obligations. Additionally, we have recorded a $0.7 million liability, which represents the fair value, of the conditional asset retirement obligations related to the retirement of our Val Verde gathering system. During 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded asset retirement obligations.

Equity earnings of $35.1 million for the year ended December 31, 2006 were generated from our ownership interest in Jonah. Beginning August 1, 2006, revenues and costs and expenses of Jonah are now included in equity earnings based upon our ownership interest in Jonah. Prior to August 1, 2006, Jonah was wholly-owned, and its revenues and costs and expenses were included in the individual revenues and costs and expenses line items. For the period from August 1, 2006 through December 31, 2006, our sharing in the revenues and costs and expenses of Jonah was 99.7%. Jonah's income from continuing operations for the year ended December 31, 2006 increased $17.7 million, compared to income from continuing operations for the year ended December 31, 2005, primarily due to increased volumes generated from the completion of Phase IV of the Jonah expansion project and increased revenues generated from the completion of a portion of Phase V of the expansion project in December 2005.

For the full year ended December 31, 2006, Jonah's gathering volumes averaged 1.3 Bcf per day, compared with approximately 1.2 Bcf per day for the year ended December 31, 2005. Jonah's volumes gathered increased 58.7 Bcf for the year ended December 31, 2006, primarily as a result of the Phase IV expansion, compared with the year ended December 31, 2005. Jonah's average fee per MMcf increased 8% primarily due to lower system wellhead pressures during 2006 as a result of the Phase IV expansion. Jonah's condensate sales volumes increased 19% for the year ended December 31, 2006, primarily due to the increase in gathering volumes, compared with the year ended December 31, 2005.

Interest income increased $0.4 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher interest income earned on cash investments and other investing activities.

Discontinued Operations

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and recommended for approval by the ACG Committee and a fairness opinion was rendered by an investment banking firm. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was$19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2006 and 2005, are presented below (in thousands):

	For Year Ended December 31,	
	2006	2005
Operating revenues:		
Sales of petroleum products	$ 3,828	$ 10,479
Other	932	2,975
Total operating revenues	4,760	13,454
Costs and expenses:		
Purchases of petroleum products	3,000	8,870
Operating expense	182	692
Depreciation and amortization	51	612
Taxes — other than income taxes	30	130
Total costs and expenses	3,263	10,304
Income from discontinued operations	$ 1,497	$ 3,150

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Pioneer plant decreased $0.8 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to the sale of the Pioneer plant on March 31, 2006, partially offset by increased NGL prices. The Pioneer gas processing plant was completed during the first quarter of 2004, as a part of Jonah's Phase III expansion to increase the processing capacity in southwestern Wyoming. Pioneer's processing agreements allowed the producers to elect annually whether to be charged under a fee-based arrangement or a fee plus keep-whole arrangement. Under the fee-based election, Jonah received a fee for its processing services. Under the fee plus keep-whole election, Jonah received a lower fee for its processing services, retained and sold the NGLs extracted during the process and delivered to producers the residue gas equivalent in energy to the natural gas received from the producers. Jonah sold the NGLs it retained and purchased gas to replace the equivalent energy removed in the liquids. For the 2005 and 2006 periods, the producers elected the fee plus keep-whole arrangement.

Interest Expense and Capitalized Interest

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Interest expense increased $15.4 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to the issuance of our 7.000% fixed-rate junior subordinated notes in May 2007 (see Note 12 in the Notes to Consolidated Financial Statements), $2.5 million of expense reductions recorded in the second quarter of 2006 related to interest rate swaps, higher short-term floating interest rates on our revolving credit facility in 2007 and the termination of the floating rate interest rate swap in September 2007.

Capitalized interest increased $0.3 million for the year ended December 31, 2007, compared with the year ended December 31, 2006, due to higher construction work-in-progress balances in 2007 as compared to the 2006 period.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Interest expense increased $8.2 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, primarily due to higher outstanding borrowings and higher short term floating interest rates on our revolving credit facility, partially offset by reductions in interest expense during 2006 related to our interest rate swaps and $2.0 million of interest expense recognized in the 2005 period related to the termination of a treasury lock (see Note 6 in the Notes to Consolidated Financial Statements).

Capitalized interest increased $3.9 million for the year ended December 31, 2006, compared with the year ended December 31, 2005, due to higher construction work-in-progress balances in 2006 as compared to the 2005 period as well as construction of the Phase V expansion project during 2006 related to our investment in Jonah.

Income Taxes — Revised Texas Franchise Tax

Provision for income taxes is applicable to our state tax obligations under the Revised Texas Franchise Tax enacted in May 2006. At December 31, 2007, we had a $1.2 million current tax liability and a less than $0.1 million deferred tax asset, while at December 31, 2006, we had a $0.7 million deferred tax liability. During the year ended December 31, 2007, we recorded a reduction to deferred income tax expense of $0.7 million and an increase in current income tax expense of $1.2 million. During the year ended December 31, 2006, we recorded deferred income tax expense of approximately $0.7 million. The current and deferred income taxes are shown on our statements of consolidated income as provision for income taxes.

Financial Condition and Liquidity

Cash generated from operations, credit facilities and debt and equity offerings are our primary sources of liquidity. At December 31, 2007 and 2006, we had working capital deficits of $431.2 million and $9.8 million, respectively. Of the $431.2 million deficit at December 31, 2007, $354.0 million relates to the classification of TE Products' Senior Notes as short-term (see Note 12 in the Notes to Consolidated Financial Statements and Credit Facilities below). At December 31, 2007, we had approximately $186.5 million in available borrowing capacity under our revolving credit facility. On January 1, 2008, we had $1.0 billion available under our new term credit agreement (see Note 12 in the Notes to Consolidated Financial Statements and Credit Facilities below) to cover any working capital needs. Cash flows for the years ended December 31, 2007, 2006 and 2005 were as follows (in thousands):

	For Year Ended December 31,		
	2007	2006	2005
Cash provided by (used in):			
Continuing operating activities	$ 350,572	$ 271,552	$ 250,723
Operating activities	350,572	273,073	254,505
Investing activities	(317,400)	(273,716)	(350,915)
Financing activities	(33,219)	594	80,107

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Operating Activities

Net cash flow from continuing operating activities was $350.6 million for the year ended December 31, 2007 compared to $271.6 million for the year ended December 31, 2006. The following were the principal factors resulting in the $79.0 million increase in net cash flow from continuing operating activities:

- The improvement in cash flow is generally due to increased earnings (see "Results of Operations" within this Item 7) and the timing of related cash collections and disbursements between years.
- Cash received for crude oil inventory was $4.8 million for the year ended December 31, 2007, compared to cash payments of $46.3 million for the year ended December 31, 2006. The increase in cash received is related to changes in activities relating to crude oil inventory. As part of our crude oil marketing activity, we purchase crude oil and simultaneously enter into offsetting sales contracts for physical delivery in future periods. These transactions result in an increase in the amount of inventory carried on our books until the crude oil is sold. The substantial majority of inventory related to these contracts as of December 31, 2007 has been contracted for sale in the first quarter of 2008; however, new contracts may be executed, which would result in higher inventory balances being held

in future balance sheet periods. At December 31, 2007, inventory balances related to these types of transactions were lower compared to the balance at December 31, 2006.

- Cash distributions received from unconsolidated affiliates increased $59.4 million primarily due to an increase of $70.0 million in distributions received from our equity investment in Jonah as a result of the formation of the joint venture on August 1, 2006. Distributions received from our equity investment in Seaway decreased $8.1 million primarily due to the reduction of our sharing ratio to 40% in 2007 from 47% in 2006, and lower Seaway revenues, which were negatively impacted by the unexpected temporary shutdown of several regional refineries for maintenance and repairs. Distributions received from our equity investment in MB Storage decreased $2.5 million due to the sale of our investment in MB Storage on March 1, 2007.

- Cash paid for interest, net of amounts capitalized, increased $16.1 million year-to-year primarily due to higher outstanding balances on our variable rate revolving credit facility, the issuance of junior subordinated notes in May 2007 and the payment of a make-whole premium related to the redemption of $35.0 million of TE Product's Senior Notes. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2008, we expect interest payments on our fixed rate Senior Notes and junior subordinated notes for 2008 to be approximately $77.7 million. We expect to make our interest payments with cash flows from operating activities.

Investing Activities

Net cash flows used in investing activities was $317.4 million for the year ended December 31, 2007 compared to $273.7 million for the year ended December 31, 2006. The following were the principal factors resulting in the $43.7 million increase in net cash flows used in investing activities:

- Investments in unconsolidated affiliates increased $70.3 million, which includes a $66.5 million increase in contributions for our ownership interest in the Jonah joint venture with Enterprise Products Partners primarily for capital expenditures on its Phase V expansion and an $8.6 million increase in contributions to Centennial, partially offset by a $4.8 million decrease in contributions to MB Storage, which was sold on March 1, 2007. Contributions to Centennial in 2007 included $6.1 million for contractual obligations that were created upon formation of Centennial and $5.0 million for debt service requirements.

- Capital expenditures increased $58.2 million primarily due to an increase in organic growth projects year-to-year and higher spending to sustain existing operations, including pipeline integrity (see "Other Considerations — Future Capital Needs and Commitments" below). Cash paid for linefill on assets owned increased $33.0 million year-to-year primarily due to increases in our propane inventory related to the sale of our ownership interest in MB Storage on March 1, 2007 and the completion of organic growth projects in our Upstream Segment. Because we sold our interest in MB Storage and we have location exchange requirements to provide barrels to shippers at Mont Belvieu, we increased our long-term propane inventory.

- Proceeds from the sales of assets and ownership interests for the year ended December 31, 2007 were $165.1 million, which includes $137.3 million from the sale of TE Products' ownership interests in MB Storage and its general partner and $18.5 million for the sale of other Downstream Segment assets, all to Louis Dreyfus on March 1, 2007; $8.0 million for the sale of Downstream Segment assets to Enterprise Products Partners in January 2007 (see Note 10 in the Notes to Consolidated Financial Statements); and $1.3 million for the sale of various Upstream Segment assets in the third quarter of 2007. Proceeds from the sales of assets for the year ended December 31, 2006 was $51.6 million, of which $38.0 million related to cash proceeds received from the sale of the Pioneer plant in the Midstream Segment on March 31, 2006, and $11.7 million of cash proceeds received from the sale of certain crude oil pipeline assets from the Upstream Segment and products pipeline assets from the Downstream Segment to an affiliate of Enterprise Products Partners in October 2006 (see Note 10 in the Notes to Consolidated Financial Statements).

- Cash paid for the acquisition of assets for the year ended December 31, 2007 was $12.9 million, of which $6.2 million was for Downstream Segment assets and $6.7 million was for Upstream Segment assets (see Note 10 in the Notes to Consolidated Financial Statements). For the year ended December 31, 2006, cash paid for the acquisition of assets was $20.5 million for Downstream Segment assets.
- During the year ended December 31, 2007, we paid $3.3 million related to customer reimbursable commitments.

Financing Activities

Cash flows used in financing activities totaled $33.2 million for the year ended December 31, 2007, compared to cash flows provided by financing activities of $0.6 million for the year ended December 31, 2006. The following were the principal factors resulting in the $33.8 million increase in cash used in financing activities:

- Borrowings under our revolving credit facility offset repayments under our revolving credit facility during the year ended December 31, 2007, while net borrowings under our revolving credit facility during the year ended December 31, 2006 were $84.1 million.
- Cash distributions to our partners increased $15.9 million year-to-year due to an increase in the number of Units outstanding and our quarterly cash distribution rates. We paid cash distributions of $294.5 million ($2.74 per Unit) and $278.6 million ($2.70 per Unit) during each of the years ended December 31, 2007 and 2006, respectively. Additionally, we declared a cash distribution of $0.695 per Unit for the quarter ended December 31, 2007. We paid the distribution of $74.8 million on February 7, 2008 to unitholders of record on January 31, 2008.
- Net proceeds from the issuance of Units decreased $193.4 million year-to-year. We generated $195.1 million in net proceeds from an underwritten equity offering in July 2006 from the public issuance of 5.8 million Units. In 2007, we received $1.7 million in net proceeds related to the issuance of Units to employees under the employee unit purchase plan and the issuance of Units in connection with our DRIP (see Note 13 in the Notes to Consolidated Financial Statements).
- We received $295.8 million from the issuance in May 2007 of our 7.000% junior subordinated notes due June 2067 (net of debt issuance costs of $3.7 million) (see Note 12 in the Notes to Consolidated Financial Statements).
- In October 2007, TE Products redeemed $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest (see Note 12 in the Notes to Consolidated Financial Statements).
- We received $1.4 million in proceeds from the termination of treasury locks in May 2007, and we paid $1.2 million for the termination of an interest rate swap in September 2007 (see Note 6 in the Notes to Consolidated Financial Statements).

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Operating Activities

Net cash flow from continuing operating activities was $271.6 million for the year ended December 31, 2006 compared to $250.7 million for the year ended December 31, 2005. The following were the principal factors resulting in the $20.9 million increase in net cash flow from continuing operating activities:

- The improvement in cash flow is generally due to increased earnings (see “Results of Operations” within this Item 7) and the timing of related cash collections and disbursements between years.

- Cash payments for crude oil inventory were $46.3 million for the year ended December 31, 2006, compared to cash received of $0.7 million for the year ended December 31, 2005.
- Cash distributions received from unconsolidated affiliates increased $26.4 million primarily due to an increase of $30.0 million in distributions received from our equity investment in Jonah and a $0.5 million increase in distributions received from our equity investment in MB Storage, partially offset by a $4.1 million decrease in distributions received from our equity investment in Seaway.
- Cash paid for interest, net of amounts capitalized, increased $5.8 million year-to-year primarily due to higher outstanding balances on our variable rate revolving credit facility.

Investing Activities

Net cash flows used in investing activities was $273.7 million for the year ended December 31, 2006 compared to $350.9 million for the year ended December 31, 2005. The following were the principal factors resulting in the $77.2 million decrease in net cash flows used in investing activities:

- Cash paid for the acquisition of assets decreased $91.8 million. Cash paid for the acquisition of assets for the year ended December 31, 2006 was $20.5 million for Downstream Segment assets. Cash paid for the acquisition of assets for the year ended December 31, 2005 was $112.2 million, of which $69.0 million was for Downstream Segment assets and $43.2 million was for Upstream Segment assets.
- Capital expenditures decreased $50.5 million primarily due to the deconsolidation of Jonah. As a result of the deconsolidation of Jonah on August 1, 2006, amounts related to Jonah capital expenditures are reported as joint venture contributions. Cash paid for linefill on assets owned decreased $8.0 million year-to-year primarily due to a lower level of asset acquisitions and related long-term inventory purchases in our Upstream Segment in 2006 compared to 2005.
- Proceeds from the sales of assets for the year ended December 31, 2006 were $51.6 million, of which $38.0 million related to the Pioneer plant sale in the Midstream Segment. Proceeds from the sales of assets for the year ended December 31, 2005 were $0.5 million.
- Investments in unconsolidated affiliates increased $124.1 million, which includes $121.0 million in contributions for our ownership interest in Jonah, a $2.5 million increase in contributions to Centennial and a $0.5 million increase in contributions to MB Storage.

Financing Activities

Cash flows provided by financing activities totaled $0.6 million for the year ended December 31, 2006, compared to $80.1 million for the year ended December 31, 2005. The following were the principal factors resulting in the $79.5 million decrease in cash provided by financing activities:

- Net proceeds from the issuance of Units decreased $83.7 million year-to-year. We generated $195.1 million in net proceeds from the 2006 public issuance of 5.8 million Units, while in 2005, we generated $278.8 million in net proceeds from the 2005 public issuance of 7.0 million Units.
- Cash distributions to our partners increased $27.5 million year-to-year due to an increase in the number of Units outstanding and our quarterly cash distribution rates. We paid cash distributions of $278.6 million ($2.70 per Unit) and $251.1 million ($2.68 per Unit) during each of the years ended December 31, 2006 and 2005, respectively.
- Net borrowings under our revolving credit facility during the year ended December 31, 2006 were 84.1 million, while net borrowings under our revolving credit facility during the year ended December 31, 2005 were $52.9 million. Debt issuance costs decreased $0.5 million year-to-year.

Other Considerations

Registration Statements

We have a universal shelf registration statement on file with the SEC that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof. After taking into account past issuances of securities under this registration statement, as of December 31, 2007, we have the ability to issue approximately $1.2 billion of additional securities under this registration statement, subject to customary marketing terms and conditions.

In September 2007, we filed a registration statement with the SEC authorizing the issuance of up to 10,000,000 Units in connection with our DRIP. The DRIP provides owners of our Units a voluntary means by which they can increase the number of Units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional Units. Units purchased through the DRIP may be acquired at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. As of December 31, 2007, 39,796 Units have been issued in connection with the DRIP.

Credit Facilities

We had in place a $700.0 million unsecured revolving credit facility, including the issuance of letters of credit ("Revolving Credit Facility"), which matured on December 13, 2011. On December 18, 2007, we amended the Revolving Credit Facility ("Fifth Amendment"). The maturity date was extended to December 12, 2012, and the Fifth Amendment allows us to request unlimited one-year extensions of the maturity date, subject to lender approval and satisfaction of certain other conditions. The Fifth Amendment contains an accordion feature whereby the total amount of the bank commitments may be increased, with lender approval and the satisfaction of certain other conditions, from $700.0 million up to a maximum amount of $1.0 billion. The Fifth Amendment also increased the aggregate outstanding principal amount of swing line loans or same day borrowings permitted under the Revolving Credit Facility from $25.0 million to $40.0 million. The interest rate is based, at our option, on either the lender's base rate, or LIBOR rate, plus a margin, in effect at the time of the borrowings. The applicable margin with respect to LIBOR rate borrowings is based on our senior unsecured non-credit enhanced long-term debt rating issued by Standard & Poor's Rating Services and Moody's Investors Service, Inc. The Fifth Amendment added a term-out option to the Revolving Credit Facility in which we may, on the maturity date, convert the principal balance of all revolving loans then outstanding into a non-revolving one-year term loan. Upon the conversion of the revolving loans to term loans pursuant to the term-out option, the applicable LIBOR spread will increase by 0.125% per year, and if immediately prior to such borrowing the total outstanding revolver borrowings then outstanding exceeds 50% of the total lender commitments, the applicable LIBOR spread with respect to borrowings will increase by an additional 10 basis points.

Prior to the effectiveness of the Fifth Amendment, the Revolving Credit Facility contained financial covenants that required us to maintain (i) a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00 and (ii) a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions), in each case with respect to specified twelve month periods. The Fifth Amendment eliminated the interest coverage requirement and provides us additional flexibility with respect to our leverage test by increasing the threshold ratio of Consolidated Funded Debt to Pro Forma EBITDA to 5.00 to 1.00 (and, if after giving effect to a permitted acquisition the ratio exceeds 5.00 to 1.00, the threshold ratio will be increased to 5.50 to 1.00 for the fiscal quarter in which such acquisition occurs and the first full fiscal quarter following such acquisition. Other restrictive covenants in the Revolving Credit Facility limit our ability, and the ability of certain of our subsidiaries, to, among other things, incur certain additional indebtedness, make distributions in excess of Available Cash (see Note 13 in the Notes to Consolidated Financial Statements), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. The credit agreement restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other third-party debt in the aggregate principal amount of $50.0 million and allows for the issuance of certain hybrid securities of up to 15% of our Consolidated Total Capitalization (as defined therein). Our obligations under the Revolving Credit Facility are guaranteed by the Subsidiary Guarantors. At December 31, 2007, $490.0 million was outstanding under the

Revolving Credit Facility at a weighted average interest rate of 5.71%. At December 31, 2007, we were in compliance with the covenants of the Revolving Credit Facility.

On December 21, 2007, we entered into a senior unsecured term credit agreement (“Term Credit Agreement”), with a borrowing capacity of $1.0 billion that matures on December 19, 2008. Term loans may be drawn in up to five separate drawings, each in a minimum amount of $75.0 million. Amounts repaid may not be re-borrowed, and the principal amount of all term loans are due and payable in full on the maturity date. We are required to make mandatory principal repayments on the outstanding term loans from 100% of the net cash proceeds we receive from (i) any asset sale excluding asset sales made in the ordinary course of business and sales to the extent aggregate proceeds are less than $25.0 million, and (ii) subject to specified exceptions, issuances of debt or equity. The interest rate is based, at our option, on either the lender’s base rate, or LIBOR rate, plus a margin, in effect at the time of the borrowings. The applicable margin with respect to LIBOR rate borrowings is based on our senior unsecured non-credit enhanced long-term debt rating issued by Standard & Poor’s Rating Services and Moody’s Investors Service, Inc. Financial covenants in the Term Credit Agreement require us to maintain a ratio of Consolidated Funded Debt to Pro Forma EBTIDA (as defined and calculated in the facility) of less than 5.00 to 1.00 (subject to adjustment for specified acquisitions, as described above with respect to our Revolving Credit Facility). Other restrictive covenants in the Term Credit Agreement limit our ability, and the ability of certain of our subsidiaries, to, among other things, incur certain indebtedness, make distributions in excess of Available Cash (see Note 13 in the Notes to Consolidated Financial Statements), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. Our obligations under the Term Credit Agreement are guaranteed by the Subsidiary Guarantors. At December 31, 2007, no amounts were outstanding under the Term Credit Agreement, and we were in compliance with the covenants of the Term Credit Agreement.

Junior Subordinated Notes

In May 2007, we issued and sold $300.0 million in principal amount of junior subordinated notes under our universal shelf registration statement. For additional information regarding this debt offering and the terms and covenants of the notes, see Note 12 in the Notes to Consolidated Financial Statements.

Retirement of TE Products Senior Notes

In October 2007, we repurchased $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest, and on January 28, 2008, we redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. Additionally, the $180.0 million principal amount of 6.45% TE Products Senior Notes matured and was repaid on January 15, 2008. We funded the retirement of both series with borrowings under our Term Credit Agreement. For further information, please see Note 12 in the Notes to Consolidated Financial Statements.

Future Capital Needs and Commitments

We estimate that capital expenditures, excluding acquisitions and joint venture contributions, for 2008 will be approximately $403.0 million (including $13.0 million of capitalized interest). We expect to spend approximately $321.0 million for revenue generating projects, which includes $153.0 million for our expected spending on the Motiva project. We expect to spend approximately $57.0 million to sustain existing operations (including $17.0 million for pipeline integrity) including life-cycle replacements for equipment at various facilities and pipeline and tank replacements among all of our business segments. We expect to spend approximately $12.0 million to improve operational efficiencies and reduce costs among all of our business segments. Additionally, we expect to invest approximately $124.0 million (including $3.0 million of capitalized interest) in our Jonah joint venture during 2008 for the completion of the Phase V expansion and additional facilities to expand the Pinedale field production.

During 2008, TE Products may be required to contribute cash to Centennial to cover capital expenditures, debt service requirements or other operating needs. We continually review and evaluate potential capital improvements and expansions that would be complementary to our present business operations. These expenditures can vary greatly depending on the magnitude of our transactions. We may finance capital expenditures through internally generated funds, debt or the issuance of additional equity.

Liquidity Outlook

As of February 1, 2008, after giving effect to borrowings under the Term Credit Agreement to retire or redeem the TE Products Senior Notes and to fund a portion of our marine transportation business acquisition, we had approximately $2.2 billion of consolidated debt outstanding, consisting of $520.0 million of borrowings under our Revolving Credit Facility, $715.0 million of borrowings under our Term Credit Agreement, $700.0 million principal amount of Senior Notes and $300.0 million principal amount of junior subordinated notes. Additionally, on February 1, 2008, we issued approximately 4.85 million Units for our acquisition of the marine transportation business.

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and to complete the Jonah expansion, revenue generating expenditures, interest payments on our Senior Notes, junior subordinated notes and Revolving Credit Facility, distributions to our unitholders and General Partner and acquisitions of new assets or businesses. Our operating cash requirements and capital expenditures to sustain existing operations for 2008 are expected to be funded through our cash flows from operating activities. Long-term cash requirements for expansion projects, acquisitions and debt repayments are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities, joint venture distributions and possibly the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

We expect to repay the long-term, senior and junior unsecured obligations through the issuance of additional long-term senior or junior unsecured debt, issuance of additional equity, with proceeds from dispositions of assets, cash flow from operations or any combination of the above items.

Off-Balance Sheet Arrangements

We do not rely on off-balance sheet borrowings to fund our acquisitions. We have no material off-balance sheet commitments for indebtedness other than the limited guaranty of Centennial debt, the limited guarantee of Centennial catastrophic events as discussed below and an outstanding letter of credit (see Note 12 in the Notes to Consolidated Financial Statements). In addition, we have entered into various operating leases covering assets utilized in several areas of our operations.

At December 31, 2007 and 2006, Centennial's debt obligations consisted of $140.0 million borrowed under a master shelf loan agreement, and $150.0 million ($140.0 million borrowed under a master shelf loan agreement and $10.0 million borrowed under an additional credit agreement, which terminated in April 2007), respectively. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under this credit facility. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $70.0 million each at December 31, 2007. Provisions included in the Centennial credit facility required that certain financial metrics be achieved and for the guarantees to be removed by May 2007. These metrics were not achieved, and the Centennial credit facility was amended in May 2007 to require the guarantees to remain throughout the life of the debt. As a result of the guarantee, at December 31, 2007, TE Products has a liability of $9.5 million, which represents the present value of the estimated amount, based on a probability estimate, we would have to pay under the guarantee. In January 2007, we entered into an amended guaranty agreement with the lender bank. Under this amended guaranty, we, together with our affiliates, TCTM, TEPPCO Midstream and TE Products (collectively, "TEPPCO Guarantors"), jointly and severally agreed to guaranty 50% of the obligations of Centennial under its master shelf loan agreement. The amended guaranty also has a credit maintenance requirement whereby we may be required to provide additional credit support or pay certain fees if our credit ratings fall below levels specified in the amended guaranty.

TE Products, Marathon and Centennial have also entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, at December 31, 2007, TE Products has a liability of $4.1 million, which represents the present value of the estimated amount, based on a probability estimate, we would have to pay under the guarantee.

If a catastrophic event were to occur and we were required to contribute cash to Centennial, such contributions might be covered by our insurance (net of deductible), depending upon the nature of the catastrophic event.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various equipment. Lease expense related to this equipment is approximately $5.2 million per year (see Contractual Obligations below). We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees. We do not believe that any performance under the guarantee would have a material effect on our financial condition, results of operations or cash flows.

Contractual Obligations

The following table summarizes our debt repayment obligations and material contractual commitments as of December 31, 2007 (in thousands):

	Amount of Commitment Expiration Per Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Revolving Credit Facility, due 2012	$ 490,000	$ —	$ —	$ 490,000	$ —
6.45% Senior Notes due 2008 (1) (2) (3)	180,000	180,000	—	—	—
7.625% Senior Notes due 2012 (2)	500,000	—	—	500,000	—
6.125% Senior Notes due 2013 (2)	200,000	—	—	—	200,000
7.51% Senior Notes due 2028 (1) (2) (3)	175,000	175,000	—	—	—
7.00% Junior Subordinated Notes due 2067 (2)	300,000	—	—	—	300,000
Make-whole premium on 7.51% Senior Notes redeemed January 28, 2008 (3)	6,571	6,571	—	—	—
Interest payments (4)	1,633,447	105,634	198,708	178,480	1,150,625
Debt and interest subtotal	$ 3,485,018	$ 467,205	$ 198,708	$ 1,168,480	$ 1,650,625
Operating leases (5)	$ 64,915	$ 13,397	$ 21,427	$ 17,125	$ 12,966
Purchase obligations: (6)					
Product purchase commitments:					
Estimated payment obligation:					
Crude oil	$ 387,210	$ 387,210	$ —	$ —	$ —
Other	$ 3,971	$ 2,199	$ 1,196	$ 558	$ 18
Underlying major volume commitments:					
Crude oil (in MBbls)	4,492	4,492	—	—	—
Service payment commitments	$ 8,974	$ 4,499	$ 4,475	$ —	$ —
Contributions to Jonah (7)	$ 124,000	$ 124,000	$ —	$ —	$ —
Capital expenditure obligations (8)	$ 11,335	$ 11,335	$ —	$ —	$ —
Standby letter of credit (9)	$ 23,494	$ 23,494	$ —	$ —	$ —
Other liabilities and deferred credits (10)	$ 27,122	$ —	$ 4,835	$ 4,259	$ 18,028
Total	$ 4,136,039	$ 1,033,339	$ 230,641	$ 1,190,422	$ 1,681,637

(1) Obligations of TE Products.

(2) At December 31, 2007, the 7.51% Senior Notes and the 7.625% Senior Notes include a deferred loss of $1.0 million and a deferred gain of $23.2 million, respectively, both net of amortization, from interest rate swap terminations (see Note 6 in the Notes to Consolidated Financial Statements). At December 31, 2007, our 6.45% Senior Notes, our 7.625% Senior Notes, our 6.125% Senior Notes and our 7.00% junior subordinated notes include $2.2 million of unamortized debt discounts. The fair value adjustments, the deferred gain/loss adjustment and the unamortized debt discounts are excluded from this table.

(3) On January 28, 2008, TE Products redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes outstanding at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. The 6.45% TE Products Senior Notes matured on January 15, 2008. Retirement of these series of notes was funded with borrowings under our Term Credit Agreement (see Note 22 in the Notes to Consolidated Financial Statements for additional information).

(4) Includes interest payments due on our Senior Notes and junior subordinated notes and interest payments and commitment fees due on our Revolving Credit Facility. The interest amount calculated on the Revolving Credit Facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(5) We lease property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year for the periods indicated. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. Total rental expense for the years ended December 31, 2007, 2006 and 2005, was $22.1 million, $25.3 million and $24.0 million, respectively.

(6) We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The preceding table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at December 31, 2007. The majority of contractual commitments we make for the purchase of crude oil range in term from a thirty-day evergreen to one year. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice.

(7) Expected contributions to Jonah in 2008 for our share of the Phase V expansion and other capital expenditures.

(8) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services rendered or products purchased.

(9) At December 31, 2007, we had outstanding a $23.5 million standby letter of credit in connection with crude oil purchased during the fourth quarter of 2007. The payable related to these purchases of crude oil is expected to be paid during the first quarter of 2008.

(10) Includes approximately $10.1 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $12.8 million related to our estimated long-term portion of our liabilities under our guarantees to Centennial for its credit agreement and for a catastrophic event. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

On December 21, 2007, we entered into a senior unsecured Term Credit Agreement, with a borrowing capacity of $1.0 billion which matures on December 19, 2008 (see " – Credit Facilities" above).

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

Credit Ratings

Our debt securities are rated BBB- by Standard and Poors ("S&P") and Baa3 by Moody's Investors Service, Inc. ("Moody's"). S&P's rating is with a stable outlook while Moody's rating is with a negative outlook. Based upon the characteristics of the fixed/floating unsecured junior subordinated notes that we issued in May 2007, Moody's and S&P each assigned 50% equity treatment to these notes. In October 2007, our debt securities received a rating of BBB- from Fitch Ratings, with a stable outlook. Fitch Ratings assigned 75% equity treatment to the junior subordinated notes.

A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any indebtedness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Recent Accounting Pronouncements

See discussion of new accounting pronouncements in Note 3 in the Notes to Consolidated Financial Statements.

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

We are exposed to financial market risks, including changes in commodity prices and interest rates. We do not have foreign exchange risks. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices. Our Risk Management Committee has established policies to monitor and control these market risks. The Risk Management Committee is comprised, in part, of senior executives of the General Partner.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates, resulting in the realization of income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Commodity Risk Hedging Program

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

As part of our crude oil marketing business, we enter into derivative contracts such as swaps and other business hedging devices. Generally, we elect hedge accounting where permitted under SFAS 133. The terms of these contracts are typically one year or less. The purpose is to balance our position or lock in a margin and, as such, the derivative contracts do not expose us to additional significant market risk. For derivatives where hedge accounting is elected, the effective portion of changes in fair value are recorded in other comprehensive income and reclassified into earnings as such transactions affect earnings. For derivatives where hedge accounting is not elected, we mark these transactions to market and the changes in the fair value are recognized in current earnings. This results in some financial statement variability during quarterly periods.

At December 31, 2007, we had a limited number of commodity derivatives that were accounted for as cash flow hedges. These contracts will expire during 2008, and any amounts remaining in accumulated other comprehensive income will be recorded in net income. Gains and losses on these derivatives are offset against corresponding gains or losses of the hedged item and are deferred through other comprehensive income, thus minimizing exposure to cash flow risk. In addition, we had some commodity derivatives that did not qualify for hedge accounting. These financial instruments had a minimal impact on our earnings. The fair value of the open positions at December 31, 2007 was a liability of $18.9 million. No ineffectiveness was recognized as of December 31, 2007.

The following table shows the effect of hypothetical price movements on the estimated fair value ("FV") of this portfolio at the dates indicated (in thousands):

Scenario	Resulting Classification	December 31, 2006	December 31, 2007	February 12, 2008
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 741	$(18,897)	$(12,981)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	250	(33,606)	(25,213)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	1,232	(4,188)	(750)

The fair value of the open positions was based upon both quoted market prices obtained from NYMEX and from other sources such as reporting services, industry publications, brokers and marketers. The fair values were determined based upon the differences by month between the fixed contract price and the relevant forward price curve, the volumes for the applicable month and applicable discount rate.

Interest Rate Risk Hedging Program

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

We have interest rate swap agreements outstanding at December 31, 2007 that are accounted for using mark-to-market accounting.

Hedged Debt	Number of Swaps	Period Covered by Swaps	Termination Date of Swaps	Rate Swaps	Notional Value
Revolving Credit Facility, due Dec. 2012	4	Jan. 2006 to Jan. 2008	Jan. 2008	Swapped 5.18% floating rate for fixed rates ranging from 4.67% to 4.695% (1)	$200.0 million

(1) On June 30, 2007, these interest rate swap agreement were de-designated as cash flow hedges and are now accounted for using mark-to-market accounting; thus, changes in the fair value of these swaps are recognized in earnings. At December 31, 2007 and 2006, the fair values of these interest rate swaps were assets of $0.3 million and $1.4 million, respectively.

Interest Rate Swap Termination. In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. This swap agreement, designated as a fair value hedge, had a notional amount of $210.0 million and was set to mature in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products paid a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread of 147 basis points, and received a fixed rate of interest of 7.51%. During the years ended December 31, 2007, 2006 and 2005, we recognized reductions in interest expense of $0.3 million, $1.9 million and $5.6 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. The fair value of this interest rate swap was a liability of approximately $2.6 million at December 31, 2006. In September 2007, we terminated this interest rate swap agreement resulting in a loss of $1.2 million. The loss was deferred as an adjustment to the carrying value of the 7.51% Senior Notes, and approximately $0.2 million of the loss was amortized to interest expense in 2007, with the remaining balance recognized as interest expense in January 2008 at the time the 7.51% Senior Notes were redeemed.

Treasury Locks. In October 2006 and February 2007, we entered into treasury locks, accounted for as cash flow hedges, that extended through June 2007 for a notional amount totaling $300.0 million. In May 2007, these treasury locks were terminated concurrent with the issuance of junior subordinated notes (see Note 12 in the Notes to Consolidated Financial Statements). The termination of the treasury locks resulted in gains of $1.4 million, and these gains were recorded in other comprehensive income. These gains are being amortized using the effective interest method as reductions to future interest expense over the fixed rate term of the junior subordinated notes, which is ten years. In the event of early extinguishment of the junior subordinated notes, any remaining unamortized gains would be recognized in the statement of consolidated income at the time of extinguishment.

In 2007, we entered into treasury locks that extended through January 31, 2008 for a notional amount totaling $600.0 million. These instruments have been designated as cash flow hedges to offset our exposure to increases in the underlying U.S. Treasury benchmark rate that is expected to be used to establish the fixed interest rate for debt that we expect to incur in 2008. The weighted average rate under the treasury lock agreements was approximately 4.39%. The actual coupon rate of the expected debt will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium at the date of issuance. At December 31, 2007, the fair value of the treasury locks was a liability of $25.3 million. To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is incurred and will be amortized to earnings over the life of the debt. No ineffectiveness was recognized as of December 31, 2007. In January 2008, we extended the expiration date to April 30, 2008 of $600.0 million notional amount of treasury locks that were set to expire on January 31, 2008. The weighted average rate under the treasury lock agreements is approximately 4.50%.

Fair Values of Debt

The following table summarizes the estimated fair values of the Senior Notes and junior subordinated notes as of December 31, 2007 and 2006 (in thousands):

		Fair Value December 31,	
	Face Value	2007	2006
6.45% TE Products Senior Notes, due January 2008 (1)	$180,000	$179,982	$181,641
7.625% Senior Notes, due February 2012	500,000	536,765	537,067
6.125% Senior Notes, due February 2013	200,000	202,027	201,610
7.51% TE Products Senior Notes, due January 2028 (1)	175,000	181,571	221,471
7.000% Junior Subordinated Notes, due June 2067	300,000	270,485	—

(1) In October 2007, TE Products repurchased $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest, and on January 28, 2008, TE Products redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. Additionally, the $180.0 million principal amount of 6.45% TE Products Senior Notes matured and was repaid on January 15, 2008. We funded the retirement of both series with borrowings under our Term Credit Agreement (see Note 12 in the Notes to Consolidated Financial Statements and Credit Facilities above). The face value of the 7.51% TE Products Senior Notes at December 31, 2006 was $210.0 million.

Item 8. *Financial Statements and Supplementary Data*

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

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

On April 6, 2006, the ACG Committee dismissed KPMG as our independent registered public accounting firm and engaged Deloitte & Touche as our new independent registered public accounting firm. As described below, the change in independent registered public accounting firms is not the result of any disagreement with KPMG. We filed a Form 8-K on April 11, 2006 reporting a change of accountants.

During the two fiscal years ended December 31, 2005, and the subsequent interim period through April 6, 2006, there have been no disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of KPMG would have caused them to make reference thereto in their reports on financial statements for such years, and there have been no “reportable events,” as described in Item 304(a)(1)(v) of Regulation S-K.

During the two fiscal years ended December 31, 2005, and the subsequent interim period through April 6, 2006, we did not consult Deloitte & Touche regarding (i) either the application of accounting principles to a specified transaction, completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or (ii) any matter that was either the subject of a “disagreement” or a “reportable event” as set forth in Items 304(a)(1)(iv) and (v) of Regulation S-K, respectively.

We requested that KPMG furnish a letter addressed to the SEC stating whether or not it agreed with the above statements, a copy of which is filed as Exhibit 16 to this Report.

Item 9A. *Controls and Procedures*

As of the end of the period covered by this Report, our management carried out an evaluation, with the participation of our principal executive officer (the “CEO”) and our principal financial officer (the “CFO”), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on that evaluation, as of the end of the period covered by this Report, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our General Partner’s CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this Report.

MANAGEMENT’S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of management and directors of the Partnership; and

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

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on the assessment and those criteria, management believes that the Partnership maintained effective internal control over financial reporting as of December 31, 2007. The certifications of our General Partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this Report.

The Partnership's registered public accounting firm has issued an attestation report on the Partnership's internal control over financial reporting. That report appears below.

/s/ JERRY E. THOMPSON	/s/ WILLIAM G. MANIAS
Jerry E. Thompson President and Chief Executive Officer of our General Partner, Texas Eastern Products Pipeline Company, LLC	William G. Manias Vice President and Chief Financial Officer of our General Partner, Texas Eastern Products Pipeline Company, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of TEPPCO Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2007 of the Partnership and our report dated February 28, 2008 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2008

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

None.

PART III

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

Partnership Management

As is commonly the case with publicly traded partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA or service providers under the direction of the Board of Directors ("Board") and officers of our General Partner. Our unitholders do not elect the officers or directors of our General Partner. For a description of the ASA, please read "Relationship with EPCO and Affiliates" under Item 13 of this Report.

The limited liability company agreement of our General Partner provides that directors of the General Partner be appointed by its member and may be removed at any time, with or without cause, by the member. The vacancy created by any such removal shall be filled by the member. The agreement further provides that officers of the General Partner be appointed by the Board at such time and for such terms as the Board determines. Any officer of the General Partner may be removed with or without cause by the Board. However, Dan L. Duncan, who is Chairman of and controls EPCO, effectively has the ability through his indirect control of the General Partner to appoint, remove and replace any of the officers or directors of our General Partner at any time, with or without cause. Each member of the Board serves until his successor is appointed and qualified or his earlier resignation or removal. None of the officers of the General Partner serve as officers of EPCO or any of its other affiliates.

On January 1, 2008, Donald H. Daigle was appointed to the Board and also serves as a member of the ACG Committee.

Because we are a limited partnership, we are not required to comply with certain requirements of the NYSE. Accordingly, the Board is not required to be comprised of a majority of independent directors under Section 303A.01 of the NYSE Listed Company Manual. In addition, we are not required and have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which requires certain listed companies to maintain a Nominating/Corporate Governance Committee and a Compensation Committee, each consisting entirely of independent directors.

Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a "material" relationship with our General Partner or us as described in such listing standards. Based on the foregoing, the Board has affirmatively determined that Michael B. Bracy, Murray H. Hutchison, Richard S. Snell and Donald H. Daigle are "independent" directors under the NYSE listing standards. In making its determination, the Board considered the following relationships of Mr. Snell and determined that they do not constitute material relationships that affect his independence:

- From June 2000 until February 14, 2006, Mr. Snell was a director of Enterprise Products GP, the general partner of Enterprise Products Partners. The Board determined that this relationship is not material because that directorship was terminated soon after he joined our Board and, as described below, the Board determined his ownership of Enterprise Products Partners common units to be immaterial.
- Until November 2006, Mr. Snell owned 4,557 Enterprise Products Partners common units and options to purchase 40,000 Enterprise Products Partners common units; his wife owned 1,100 Enterprise Products Partners common units; and Mr. Snell and his wife owned as tenants in common 7,500 common units of Enterprise GP Holdings. Mr. Snell is the trustee of family trusts that own a total of 6,000 Enterprise Products Partners common units and 200 Enterprise GP Holdings common units. The Board determined that these relationships are not material because, consistent with principles in NYSE listing standards, the Board does not view ownership of units, by itself, as a bar to an independence finding. Further, Mr. Snell and his wife no longer own directly any Enterprise Products Partners or Enterprise GP Holdings common units, and he disclaims beneficial ownership of the units owned by the family trusts.
- Since May 2000, Mr. Snell has been a partner with the law firm of Thompson & Knight LLP in Houston, Texas, which has from time to time provided legal services for Enterprise Products Partners and its affiliates, including Mr. Duncan. For the three year period ended December 31, 2005, Mr. Duncan paid an aggregate of approximately $51,000 to Thompson & Knight for legal services. The Board determined that this relationship is not material because Thompson & Knight has performed no legal services for us or any of our affiliates, including Mr. Duncan, since Mr. Snell joined the Board and because the fees paid to his firm for prior services were minimal.
- Mr. Snell and Richard Bachmann practiced law as partners for a number of years until 1998. Mr. Bachmann was a member of the Board until December 2006 and serves as a director and executive officer of EPCO, Enterprise Products Partners and certain affiliates of Enterprise Products Partners. The Board determined that this relationship is not material because their relationship as partners terminated a number of years before Mr. Snell joined the Board.

Code of Conduct, Corporate Governance Guidelines and Charter of the Audit and Conflicts Committee

We have adopted a Code of Conduct applicable to all EPCO employees, including our principal executive officer, principal financial officer and principal accounting officer, as well as directors of our General Partner. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. A copy of the Code of Conduct is available on our website at www.teppco.com under "Investors – Corporate Governance." We intend to post on our website any amendments to, or waivers from, our Code of Conduct applicable to our senior officers.

Our Governance Guidelines address director qualification standards; director responsibilities; director access to management, and as necessary and appropriate, independent advisors; director compensation; director orientation and continuing education; and annual performance evaluation of the Board. The Charter of our ACG Committee and our Governance Guidelines are currently available on our website at www.teppco.com under Corporate Governance. Additionally, the Code of Conduct, our Corporate Governance Guidelines and the Charter of the ACG Committee are available in print, without charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request in care of Secretary, TEPPCO Partners, L.P., 1100 Louisiana Street, P.O. Box 2521, Houston, Texas 77252-2521.

Committees of the Board of Directors

Audit, Conflicts and Governance Committee

Our General Partner has an audit, conflicts and governance committee (the "ACG Committee") comprised of four board members who are independent under the rules of the SEC regarding audit committees. In February 2007, the Board combined its Audit and Conflicts Committee with its Governance Committee to for the ACG Committee. The members of the ACG Committee are Michael B. Bracy (Chairman), Murray H. Hutchison, Richard S. Snell and Donald H. Daigle. The current members of the ACG Committee are non-employee directors of the General Partner and are not officers or directors of EPCO or its subsidiaries. No member of the ACG Committee of our General Partner serves on the audit committees of more than two other public companies. Our Board has also determined that Mr. Bracy qualifies as an audit committee financial expert as defined in Item 407(d) of Regulation S-K promulgated by the SEC. Each member of the ACG Committee is financially literate within the meaning of the NYSE listing standards.

The ACG Committee assists with Board oversight of the integrity of our financial statements, compliance with legal and regulatory requirements, independence and qualifications of our independent auditors and performance of our internal audit function and of our independent auditors. The ACG Committee develops and recommends to the Board a set of governance guidelines applicable to us and reviews such guidelines from time to time. The ACG Committee also reviews and approves related party transactions (i) for which Board approval is required by our management authorization policy, (ii) where an officer or director of the General Partner or of any of our subsidiaries is a party, (iii) when requested to do so by our management or the Board, or (iv) pursuant to our Partnership Agreement or the limited liability company agreement of our General Partner. Under our Partnership Agreement, any conflict of interest and any resolution of such conflict of interest shall be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is approved by a majority of the members of the ACG Committee and our ACG Committee did not act in bad faith. For a discussion of the policies and procedures applicable to the ACG Committee's resolution of such transactions, please refer to Item 13. Certain Relationships and Related Transactions, and Director Independence, "–Review and Approval of Transactions with Related Parties."

The ACG Committee has all the power and authority required under the Sarbanes-Oxley Act of 2002 and such other powers and authority provided under our Partnership Agreement, the limited liability company agreement of our General Partner or assigned to it by the Board. The ACG Committee has sole authority to appoint, retain, replace or terminate the independent auditor. The ACG Committee is directly responsible for the compensation, evaluation and oversight of the work of the independent auditor (including resolution of disagreements between management and the independent auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attestation services for us. The independent auditor reports directly to the ACG Committee. The ACG Committee must pre-approve all audit and permitted non-audit services to be provided by the independent auditors, subject to certain de minimis exceptions, and shall ensure that the independent auditors are not engaged to perform specific non-audit services prohibited by law or regulation.

Our ACG Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our ACG Committee may do so by calling (877) 888-0002.

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NYSE Corporate Governance Listing Standards

Annual CEO Certification

On April 2, 2007, Jerry E. Thompson, our CEO, certified to the NYSE, as required by Section 303A.12(a) of the NYSE Listed Company Manual, that as of April 2, 2007, he was not aware of any violation by us of the NYSE's Corporate Governance listing standards.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. Michael B. Bracy, Murray H. Hutchison, Richard S. Snell and Donald H. Daigle are non-management directors of our General Partner and have been determined to be independent under applicable NYSE listing standards. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. Hutchison.

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

Directors and Executive Officers

The following table sets forth certain information with respect to the directors and executive officers of the General Partner as of February 28, 2008.

Name	Age	Position with Our General Partner
Michael B. Bracy	66	Director, Member of Audit, Conflicts and Governance Committee*
Murray H. Hutchison	69	Chairman of the Board, Member of the Audit, Conflicts and Governance Committee
Richard S. Snell	65	Director, Member of the Audit, Conflicts and Governance Committee
Donald H. Daigle	66	Director, Member of the Audit, Conflicts and Governance Committee
Jerry E. Thompson	58	President, Chief Executive Officer and Director
J. Michael Cockrell+	61	Senior Vice President, Commercial Upstream
William G. Manias	46	Vice President and Chief Financial Officer
John N. Goodpasture+	59	Vice President, Corporate Development
Samuel N. Brown+	51	Vice President, Commercial Downstream
Patricia A. Totten	57	Vice President, General Counsel and Secretary

* Chairman of committee

\+ See "–Employment Arrangements" in Item 11.

Michael B. Bracy was elected a director of the General Partner in March 2005, upon the acquisition of our General Partner by an affiliate of EPCO. He also serves as Vice Chairman of the Board, Chairman of the ACG Committee and an audit committee financial expert as determined under SEC rules. Prior to being elected to the Board in March 2005, Mr. Bracy served as a director of the general partner of GulfTerra Energy Partners, L.P. ("GulfTerra") from October 1998 until September 30, 2004, when it merged with Enterprise Products Partners. He was also an audit committee financial expert while serving on the board of GulfTerra's general partner. From 1993 to 1997, Mr. Bracy served as director, executive vice president and chief financial officer of NorAm Energy Corp. For nine years prior, he served in various executive capacities with NorAm Energy Corp. Mr. Bracy is a member of the board of directors of Itron, Inc.

Murray H. Hutchison was elected a director of the General Partner in March 2005, upon the acquisition of our General Partner by an affiliate of EPCO. He also serves as Chairman of the Board and is a member of the ACG Committee. Mr. Hutchison is a private investor managing his own portfolio. He also consults with corporate managements on strategic issues. Mr. Hutchison retired in 1997 as chairman and chief executive officer of the IT Group (International Technology Corporation) after serving in that position for over 27 years. Mr. Hutchison serves as chairman of the board of Huntington Hotel Corporation, as lead director of Jack in the Box Inc., and as a director on the boards of Cadiz Inc., The Olson Company, Cardium Therapeutics, Inc. and The Hobbs Sea World Research Institute.

Richard S. Snell was elected a director of the General Partner in January 2006. He also serves as a member of the ACG Committee. Mr. Snell was an attorney with the Snell & Smith, P.C. law firm in Houston, Texas, from the founding of the firm in 1993 until May 2000. Since May 2000, he has been a partner with the firm of Thompson & Knight LLP in Houston, Texas, and is a certified public accountant. Mr. Snell served as a director of Enterprise Products GP from June 2000 until his resignation in February 2006.

Donald H. Daigle was elected a director of the General Partner effective January 2008. He also serves as a member of the ACG Committee. Mr. Daigle most recently served as vice president, refining for ExxonMobil Refining and Supply Company ("ExxonMobil") from 2000 through September 2006, when he retired. Prior to serving as vice president, refining, Mr. Daigle held numerous executive and managerial posts during his forty-three year career with the ExxonMobil.

Jerry E. Thompson has served as President, Chief Executive Officer and a director of the General Partner since April 2006. Mr. Thompson was previously chief operating officer of CITGO Petroleum Corporation ("CITGO") from 2003 to March 2006, when he retired. Mr. Thompson joined CITGO in 1971 and advanced from a process engineer to positions of increasing responsibilities in the operations, supply and logistics, business development, planning and financial aspects of CITGO. He was elected vice president of CITGO's refining business in 1987 and as its senior vice president in 1998. Mr. Thompson serves as the principal executive officer of the General Partner. Mr. Thompson serves as a director on the board of directors of Susser Holdings Corporation.

J. Michael Cockrell has served as Senior Vice President, Commercial Upstream of the General Partner since February 2003. Mr. Cockrell was previously Vice President, Commercial Upstream from September 2000 until February 2003. He was appointed Vice President of the General Partner in January 1999 and also serves as President of TEPPCO Crude GP, LLC.

William G. Manias has served as Vice President and Chief Financial Officer of the General Partner since January 2006. Mr. Manias was vice president of corporate development of Enterprise Products GP from October 2004 until January 2006. He served as vice president and chief financial officer of Gulfterra from February 2004 until October 2004, and prior to that, vice president of business development and strategic planning at El Paso Energy Partners, L.P. from October 2001 to February 2004. Prior to his joining El Paso Energy Partners, L.P. in October 2001, Mr. Manias served as vice president of investment banking for J.P. Morgan Securities Inc. (formerly Chase Securities Inc.) from January 1996 to August 2001. Mr. Manias serves as principal financial and accounting officer of the General Partner.

John N. Goodpasture has served as Vice President, Corporate Development of the General Partner since November 2001. Mr. Goodpasture was previously vice president of business development for Enron Transportation Services from June 1999 until he joined the General Partner. Mr. Goodpasture serves as a director on the board of directors of Blue Dolphin Energy Company.

Samuel N. Brown has served as Vice President, Commercial Downstream of the General Partner since June 2005. He was previously Vice President, Pipeline Marketing and Business Development in our Upstream Segment from September 2000 to June 2005.

Patricia A. Totten has served as Vice President, General Counsel and Secretary of the General Partner since March 2006. She was previously associate general counsel and deputy general counsel for Enterprise Products GP from December 2002 to January 2006.

In addition to our Executive Officers, Mark G. Stockard, age 41, has served as Treasurer since May 2002 and as Director of Investor Relations since February 2007. Mr. Stockard was Assistant Treasurer of the General Partner from July 2001 until May 2002. He was previously Controller from October 1996 until May 2002. Mr.

Stockard joined the General Partner in October 1990. Tracy E. Ohmart, age 40, has served as Controller since May 2002 and as Assistant Treasurer since February 2007. Mr. Ohmart served as acting Chief Financial Officer of the General Partner from July 2005 until January 2006. Mr. Ohmart joined the General Partner in January 2001 and held various positions with the General Partner until he became Assistant Controller in May 2001. Prior to his employment with the General Partner, Mr. Ohmart spent 12 years in various positions at ARCO Pipe Line Company, most recently serving as supervisor of general accounting and policy.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Based on information furnished to the General Partner and written representation that no other reports were required, to the General Partner's knowledge, all applicable Section 16(a) filing requirements were timely complied with during the year ended December 31, 2007.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

Overview of Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. We are managed by our General Partner, the executive officers of which are employees of EPCO. Under the ASA with EPCO, we reimburse EPCO for the compensation of our executive officers (see Item 13. Certain Relationships and Related Transactions, and Director Independence, "– Relationships with EPCO and Affiliates – Administrative Services Agreement"). Throughout this Report, our CEO, CFO and the three other most highly compensated executive officers serving at December 31, 2007 are referred to as the "Named Executive Officers" and are included in the Summary Compensation Table below. Compensation paid or awarded by us in 2006 and 2007 with respect to the Named Executive Officers reflects the compensation paid by EPCO allocated to us pursuant to the ASA, including an allocation of the cost of EPCO's equity-based long-term incentive plans and our long-term incentive plans. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to compensation of our Named Executive Officers. The elements of compensation, and EPCO's decisions regarding the determination of payments, are not subject to approvals by our Board or ACG Committee, except for awards under our and EPCO's long-term incentive plans. Awards under EPCO's and our long-term incentive plans are approved by our ACG Committee. We do not have a separate compensation committee (see Item 10. Directors, Executive Officers and Corporate Governance, "– Partnership Management").

Compensation Objectives

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (e.g., benefits, work environment, career development), are intended to provide a total rewards package to employees that provides competitive compensation opportunities to align and drive employee performance toward the creation of sustained long-term unitholder value, which will also allow the attraction, motivation and retention of high quality talent with the skills and competencies we require.

Components of Executive Officer Compensation and Compensation Decisions

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based compensation. During 2006 and 2007, elements of compensation for our Named Executive Officers consisted of the following:

- annual base salary;
- discretionary annual cash awards;
- awards under our and EPCO's long-term incentive plans; and
- other compensation, including very limited perquisites.

In order to assist Mr. Duncan and EPCO with compensation decisions, Jerry E. Thompson, our CEO, and the Senior Vice President of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers other than Mr. Thompson. Mr. Duncan, after consulting with the Senior Vice President of Human Resources for EPCO, independently makes compensation decisions with respect to Mr. Thompson. In making these compensation decisions for the Named Executive Officers, including Mr. Thompson, EPCO has in the past and is likely in the future to consider market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, various relevant compensation surveys. EPCO considered market data in a 2004-2005 survey prepared for it by an outside compensation consultant, but did not otherwise consult with compensation consultants in determining 2006 or 2007 compensation for our Named Executive Officers. During late 2006, EPCO engaged an outside compensation consultant to prepare a report that it expects to consider when determining future compensation, but EPCO did not use this report in making decisions on any 2006 or 2007 compensation for any of our Named Executive Officers. Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our Named Executive Officers in connection with determining compensation for services performed for us; rather, Mr. Duncan and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that Mr. Duncan may take into account in making the case-by-case compensation determinations include total value of wealth accumulated and the appropriate balance of internal pay equity among executive officers. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority, except for equity awards under our and EPCO's long-term incentive plans, as discussed below.

Discretionary cash awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the executive officers and drive performance in support of our business strategies, at both the partnership and individual levels. It is EPCO's general policy to pay these awards during the first quarter of each year.

The 2006 and 2007 awards granted to the Named Executive Officers under the long-term incentive plans were approved by our ACG Committee taking into account recommendations that were the result of consultation among Mr. Duncan and the Senior Vice President of Human Resources for EPCO. The long-term incentive component of our compensation package is intended to provide a means for key employees providing services to us to develop a sense of proprietorship and personal involvement in the development and financial success of our Partnership through equity-based awards. The intended result of these awards is to align the long-term interests of our executive officers with those of our unitholders.

For 2007, the Named Executive Officers were granted restricted units, unit options and unit appreciation rights ("UARs") under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP"). The 2006 LTIP, which was approved by our unitholders in December 2006, allows for various forms of equity or equity-based awards not contained in previous plans, and will further our objective of having a flexible means by which to incentivize employees and non-employees directors, in contrast to our prior practice of making equity-based awards comprised only of phantom units. The mix of awards is primarily intended to align our compensation philosophy and objectives with those of EPCO. Restricted units awarded to our Named Executive Officers in 2007 vest on May 22, 2011. As used in the context of the 2006 LTIP, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires. Unit options awarded to our Named Executive Officers in 2007 vest on May 22, 2011 and expire on May 21, 2017. UARs awarded to our Named Executive Officers in 2007 vest on May 22, 2012 and expire on the same date. The exercise price of unit options or UARs awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of a Unit as of the date of grant.

For 2006, all unit-based awards were made in the form of phantom units that provide for a cash payment on vesting. Prior to the adoption of the 2006 LTIP discussed above, our General Partner's practice was to award phantom units to executive officers under the Texas Eastern Products Pipeline Company Retention Incentive Compensation Plan ("1999 Plan") or the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP"). Vesting of phantom units issued under the 2000 LTIP is based upon the performance of the Partnership during a performance period, and the participant can receive up to 150% of the value of the phantom units at the end of the performance period. However, it is also possible that no amounts will be payable for phantom unit awards under the 2000 LTIP if certain performance conditions are not met. Vesting of phantom units issued under the 1999 Plan is based solely on the Unit price, the number of phantom units and the passage of specified vesting periods. When Mr. Thompson and Mr. Manias joined our General Partner in 2006, they were issued grants of phantom units under the 1999 Plan, primarily because the flexibility of the vesting provisions and the method of determination of compensation under this plan were deemed more appropriate compensation and better aligned with EPCO's compensation practices.

In addition to the underlying unit or unit-based awards under the 1999 Plan, the 2000 LTIP and the 2006 LTIP, prior to vesting, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units and restricted units granted to the participant under such award. Also, each employee participant awarded UARs is entitled to cash distributions equal to the product of the number of UARs outstanding for the participant and the amount equal to the excess, if any, of the distribution paid per Unit over the grant date distribution per Unit. See "– Summary of Long-Term Incentive Plans of TEPPCO" below for further information on our incentive plans.

EPCO generally does not pay for perquisites for any of our Named Executive Officers, other than reimbursement of certain club membership dues and parking, and we expect EPCO to continue its policy of covering very limited perquisites allocable to our Named Executive Officers. EPCO makes matching contributions under its 401(k) plan for the benefit of our Named Executive Officers in the same manner as for other EPCO employees. Mr. Duncan and the Senior Vice President of Human Resources for EPCO periodically review the levels of perquisites and other personal benefits provided to Named Executive Officers.

We believe that each of the base salary, cash awards and equity awards fit our overall compensation objectives and those of EPCO, as stated above, by ensuring that we retain the services of key employees providing services to us and providing incentives for such employees to exert maximum efforts for our success, thereby advancing the interests of all unitholders and the General Partner. Additionally, effective January 1, 2008 EPCO maintains a retirement plan for the benefit of employees providing services to us, including our Named Executive Officers.

Employment Arrangements and Termination or Change-in-Control Payments

Prior to the acquisition of our General Partner by an EPCO affiliate on February 24, 2005, our compensation philosophy and objectives were aligned with those of DCP, as the prior owner of our General Partner. Upon or near appointment, each Named Executive Officer and the General Partner entered into an employment agreement, which provided for annual base salaries and increases, annual bonus payments and various change in control and termination provisions. We have aligned our compensation philosophy and objectives with those of EPCO. EPCO's practice is not to enter into employment agreements with its named executive officers. Accordingly, executive officers hired since we became an affiliate of EPCO, such as Messrs. Thompson and Manias, have not entered into employment agreements with EPCO.

Three of our Named Executive Officers, Messrs. Cockrell, Brown and Goodpasture, entered into employment agreements prior to the acquisition of our General Partner by an EPCO affiliate. In January 2007, each of these individuals entered into supplements to their employment agreements ("2007 Supplements"), which provide that such employment agreements will automatically terminate on June 1, 2008 in exchange for certain retention payments if the officer remains employed until such date or is terminated without cause or because of a disability or death, or resigns as a result of relocation, prior to June 1, 2008. Additionally, recipients of awards under the 1999 Plan, the 2000 LTIP and the 2006 LTIP are entitled to payments in the event of death, disability, and in some cases, retirement pursuant to those awards. See "Employment Arrangements and Potential Payments upon Termination or Change in Control" below.

Chief Executive Officer Compensation

In connection with his appointment as President and CEO of our General Partner, Mr. Thompson received an annualized base salary of $450,000 for 2006 and a $500,000 signing bonus, with the bonus being paid in January 2007. Mr. Thompson's annual base salary for 2007 was $463,500 and his 2007 discretionary cash bonus, which was paid in February 2008, was $281,000, or 61% of his base salary for the year. In addition, at the time of his appointment, Mr. Thompson was issued 39,000 phantom units under the 1999 Plan. One-third of these phantom units vested on April 11, 2007, one-third of these phantom units will vest on April 11, 2008 and the remaining one-third will vest on April 11, 2009, assuming Mr. Thompson's continuing employment through the vesting period, or earlier in the event of death or disability. The phantom units are entitled to cash distributions made on our Units and, upon vesting, entitle Mr. Thompson to a cash payment equal to the closing price of our Units on the preceding day. Mr. Thompson is also eligible to participate in the other long-term incentive compensation programs offered by us and our General Partner, and he received awards of restricted units, unit options and UARs in May 2007. See " – Grants of Plan-Based Awards in Fiscal Year 2007" below.

Tax and Accounting Implications

Nonqualified Deferred Compensation

On October 22, 2004 the American Jobs Creation Act of 2004 was signed into law, enacting a new Section 409A of the U.S. Internal Revenue Code and changing the tax rules relating to nonqualified deferred compensation. A number of the awards under our long-term incentive plans may be considered deferred compensation for purposes of this new Section 409A of the Internal Revenue Code. The consequence of a violation of Section 409A is immediate taxation and an additional excise tax on the recipient of the compensation. While final regulations have not yet been issued, we believe our incentive awards have been structured in a manner that is compliant with or exempt from the application of Section 409A of the Internal Revenue Code.

Significant Accounting Considerations

We account for unit-based awards in accordance with SFAS 123(R), *Share-Based Payment*. SFAS 123(R) requires us to recognize compensation expense related to unit-based awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying Units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of a unit-based award is amortized to earnings on a straight-line basis over the requisite service or vesting period of the unit-based awards. Compensation for liability awards (UARs and phantom units) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability awards will be settled in cash upon vesting. We accrue compensation expense based upon the terms of each plan (see Note 4 in the Notes to Consolidated Financial Statements).

Compensation Committee Report

We do not have a separate compensation committee. As discussed in the Compensation Discussion and Analysis, we do not directly employ or compensate our Named Executive Officers. Rather, under the ASA with EPCO, we reimburse EPCO for the compensation of our executive officers. Accordingly, to the extent that decisions are made regarding the compensation policies pursuant to which our Named Executive Officers are compensated, they are made by Dan L. Duncan and EPCO (except for equity awards under our and EPCO's long-term incentive plans, as discussed above), and not by our board of directors.

In light of the foregoing, the Board of Directors of our General Partner has reviewed and discussed the Compensation Discussion and Analysis with management. Based on our review of and discussion with management with respect to the Compensation Discussion and Analysis, we determined that the Compensation Discussion and Analysis be included in this Report.

Submitted by: Murray H. Hutchison
Michael B. Bracy
Donald H. Daigle
Richard S. Snell
Jerry E. Thompson

Nothwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Exchange Act, as amended, that incorporate future filings, including this Report, in whole or in part, the foregoing report shall not be incorporated by reference into any such filings.

Summary Compensation Table

The following table reflects information regarding compensation amounts paid or accrued by us for the years ended December 31, 2007 and 2006 to each of our Named Executive Officers.

Name and Principal Position	Year	Salary ($)	Bonus ($) (3)	Unit Awards ($) (4)	Option Awards ($) (5)	All Other Compensation ($) (6)	Total ($)
Jerry E. Thompson (1)	2007	463,500	281,000	803,761	29,317	151,975	1,729,553
President and Chief Executive Officer	2006	325,673	770,000	721,000	—	58,007	1,874,680
William G. Manias (2)	2007	206,175	74,000	68,570	13,498	30,481	392,724
Vice President and Chief Financial Officer	2006	192,825	75,000	37,059	—	49,497	354,381
J. Michael Cockrell	2007	267,750	105,500	127,784	14,437	535,029	1,050,500
Senior Vice President, Commercial Upstream	2006	255,628	98,000	119,706	—	157,611	630,945
John N. Goodpasture	2007	233,375	76,000	108,965	13,342	334,865	766,547
Vice President, Corporate Development	2006	231,737	62,000	106,792	—	107,397	507,926
Samuel N. Brown	2007	241,500	76,000	95,244	13,498	281,958	708,200
Vice President, Commercial Downstream	2006	220,901	75,000	88,754	—	129,822	514,477

(1) Effective April 5, 2006, Mr. Thompson was appointed President and CEO of our General Partner.

(2) Effective January 12, 2006, Mr. Manias was appointed Vice President and CFO of our General Partner.

(3) Amounts represent discretionary annual cash awards accrued during the year. Payments under the discretionary annual cash awards program are made in the subsequent year.

(4) Amounts represent compensation expense related to phantom unit awards under the 1999 Plan and 2000 LTIP and restricted unit awards under the 2006 LTIP for the years ended December 31, 2007 and 2006, respectively. The compensation amounts are based on the following assumptions: (i) the closing price of a Unit at December 31, 2007 was $38.33; (ii) with respect to restricted units, the grant date closing price was $45.35 per Unit; (iii) (a) with respect to the 1999 Plan and the 2006 LTIP, the payout percentage is 100%, and (b) with respect to the 2000 LTIP, the performance percentage is 150%; and (iv) the percentage of the number of days in the period presented compared to the total vesting period. See discussion of the equity awards and the 2006 and 2007 grants from these equity incentive plans to the Named Executive Officers below.

(5) Amounts represent compensation expense related to unit option awards and UARs under the 2006 LTIP for the year ended December 31, 2007. With respect to the unit option awards, the compensation amounts are based on the following assumptions: (i) expected life of option of 7 years, (ii) risk-free interest rate of 4.78%; (iii) expected distribution yield on Units of 7.92%; and (iv) expected Unit price volatility on Units of 14.71%. The UARs are accounted for as liability awards under SFAS 123(R) because they are expected to be settled in cash. The compensation amounts related to UARs are based on the assumptions that (i) the closing price of a Unit at December 31, 2007 was $38.33; (ii) the payout percentage is 100%; and (iii) the percentage of the number of days in the period presented compared to the total vesting period. See discussion of the equity awards and the 2007 grants from this equity incentive plan to the Named Executive Officers below.

(6) Primary components for 2007 include (i) EPCO matching contributions under funded, qualified, defined contribution retirement plans; (ii) quarterly distributions paid on equity incentive plan awards; (iii) for Messrs. Cockrell, Brown and Goodpasture, retention payments made pursuant to employment agreement supplement payments; and (iv) the imputed value of premiums paid by EPCO for Named Executive Officers' life insurance. Components of "All

Other Compensation" for which $10,000 or more was paid to or accrued for any Named Executive Officer in 2007 as set forth below for each Named Executive Officer are as follows:

Name	Matching Contributions Under Funded Qualified Defined Contribution Retirement Plan ($)	Quarterly Distribution Equivalents Paid on Equity Incentive Plan Awards ($)	Payouts from Employment Agreement Supplement ($)	Other Compensation ($)	Total All Other Compensation ($)
Jerry E. Thompson	15,750	133,222	—	3,003	151,975
William G. Manias	15,750	12,077	—	2,654	30,481
J. Michael Cockrell	15,750	21,471	489,375	8,433	535,029
John N. Goodpasture	15,750	18,094	295,800	5,221	334,865
Samuel N. Brown	15,750	15,913	241,920	8,375	281,958

Grants of Plan-Based Awards in Fiscal Year 2007

The following table presents information concerning each grant of an award made to a Named Executive Officer in 2007 under any incentive plan. The equity incentive plan awards reflected below are restricted unit awards, unit option awards and UARs under the 2006 LTIP (see discussion of unit-based awards in Note 4 in the Notes to Consolidated Financial Statements).

		Estimated Future Payouts Under Equity Incentive Plan Awards				
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	Exercise Or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (4)
Jerry E. Thompson						
Restricted unit awards (1)	5/22/2007	—	19,000	—	—	715,170
Unit option awards (2)	5/22/2007	—	45,000	—	45.35	130,500
UARs	5/22/2007	—	66,152	—	45.35	— (3)
William G. Manias						
Restricted unit awards (1)	5/22/2007	—	3,000	—	—	112,922
Unit option awards (2)	5/22/2007	—	22,000	—	45.35	63,800
UARs	5/22/2007	—	26,461	—	45.35	— (3)
J. Michael Cockrell						
Restricted unit awards (1)	5/22/2007	—	4,200	—	—	158,090
Unit option awards (2)	5/22/2007	—	22,000	—	45.35	63,800
UARs	5/22/2007	—	33,076	—	45.35	— (3)
John N. Goodpasture						
Restricted unit awards (1)	5/22/2007	—	3,000	—	—	112,922
Unit option awards (2)	5/22/2007	—	22,000	—	45.35	63,800
UARs	5/22/2007	—	25,358	—	45.35	— (3)
Samuel N. Brown						
Restricted unit awards (1)	5/22/2007	—	3,000	—	—	112,922
Unit option awards (2)	5/22/2007	—	22,000	—	45.35	63,800
UARs	5/22/2007	—	26,461	—	45.35	— (3)

(1) Award of restricted units under the 2006 LTIP. The grant date fair value of restricted unit awards issued during 2007 was based on a market price of our Units of $45.35 per Unit on the grant date and an estimated forfeiture rate of 17%.

(2) Award of unit options under the 2006 LTIP. The grant date fair value of unit options awarded during 2007 was based on the following assumptions: (i) expected life of option of 7 years, (ii) risk-free interest rate of 4.78%; (iii) expected distribution yield on Units of 7.92%; and (iv) expected Unit price volatility on Units of 18.03%.

(3) Award of UARs under the 2006 LTIP. The UARs are accounted for as liability awards, as opposed to equity awards, under SFAS 123(R) because they are expected to be settled in cash, and as liability awards, they do not have a fixed fair value as of their grant date. The fair value of the UARs at December 31, 2007 was $51,554; $20,622; $25,777; $19,762; and $20,622 for each of Mr. Thompson, Mr. Manias, Mr. Cockrell, Mr. Goodpasture and Mr. Brown, respectively. The fair value calculations are based on the assumptions that (i) the closing price of a Unit at December 31, 2007 was $38.33; and (ii) the payout percentage is 100%.

(4) We estimate that the compensation expense we record for each Named Executive Officer with respect to these awards will equal these amounts over time. For the period in which these awards were outstanding during 2007, we recognized compensation expense of $221,788, $58,913 and $25,179 related to the restricted unit awards, the unit option awards and the UARs, respectively. The remaining portion of the fair values will be recognized as expense in future periods.

The primary elements of compensation to Named Executive Officers are annual base pay, discretionary annual cash awards and awards under long-term incentive plans. The following are summaries of long-term incentive plans under which awards are granted to participants, including certain Named Executive Officers, in order to align the long-term interest of participants with those of our unitholders. EPCO’s practice is not to enter into employment agreements with its Named Executive Officers; for a discussion regarding change of control and termination payments for each of the plans, please see “– Employment Arrangements and Potential Payments upon Termination or Change in Control.”

Summary of Long-Term Incentive Plans of TEPPCO

1999 Plan

The 1999 Plan, which was used to make awards to our Named Executive Officers in 2006, provides for the issuance of phantom unit awards as incentives to key employees. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the closing price of a Unit on the NYSE on the redemption date. Each participant is required to redeem their phantom units as they vest. Each participant is also entitled to cash distributions equal to the product of the number of phantom units outstanding for the participant and the per Unit cash distribution that we paid to our unitholders. Death or disability of the participant will result in full vesting of all remaining phantom units.

2000 LTIP

The 2000 LTIP, which was also used to make awards to our Named Executive Officers in 2006, provides key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is still an employee of EPCO, the participant will receive a cash payment equal to (i) the applicable “performance percentage” specified in the award multiplied by (ii) the number of phantom units granted under the award multiplied by (iii) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant’s performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant’s separation from service and the denominator of which is the number of days in the performance period.

The performance period applicable to awards granted in 2006 is the three-year period that commenced on January 1, 2006, and ends on December 31, 2008. Each participant’s performance percentage is the result of 100% +/- [(A) minus (C)] divided by [(C) minus (B)] where (A) is the actual Economic Value Added for the performance period, (B) is $85.8 million (which represents the actual Economic Value Added for the three-year period immediately preceding the performance period) and (C) is $118.6 million (which represents the Target Economic Value Added during the three-year performance period). No amounts will be payable under the awards granted in 2006 for the 2000 LTIP unless Economic Value Added for the three year performance period exceeds $85.8 million. The performance percentage may not exceed 150%.

The performance period applicable to awards granted in 2005 was the three-year period that commenced on January 1, 2005, and ended on December 31, 2007. Each participant's performance percentage was the result of 100% +/- [(A) minus (C)] divided by [(C) minus (B)] where (A) is the actual Economic Value Added for the performance period, (B) is $73.0 million (which represents the actual Economic Value Added for the three-year period immediately preceding the performance period) and (C) is $97.7 million (which represents the Target Economic Value Added during the three-year performance period). The performance percentage at December 31, 2007 was 148%. There are no outstanding awards granted prior to 2005.

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. EBITDA means our earnings before net interest expense, other income – net, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with GAAP, except that at his discretion the CEO of the General Partner may exclude gains or losses from extraordinary, unusual or non-recurring items. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, plus products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by our CEO at the date of award grant.

In addition to the payment described above, each participant is entitled to cash distributions equal to the product of the number of phantom units outstanding for the participant and the per Unit cash distribution that we paid to our unitholders.

2006 LTIP

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the 2006 LTIP, which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 2006 LTIP may be granted in the form of restricted units, phantom units, unit options, UARs and distribution equivalent rights. The 2006 LTIP is administered by the ACG Committee. The exercise price of unit options or UARs awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of a Unit as of the date of grant. Subject to adjustment as provided in the 2006 LTIP, awards of up to an aggregate of 5,000,000 Units may be granted under the 2006 LTIP. We reimburse EPCO for the costs allocable to 2006 LTIP awards made to employees who work in our business.

During 2007, awards of restricted units, unit options and UARs were granted to participants, including Named Executive Officers. Restricted units awarded to our Named Executive Officers in 2007 vest on May 22, 2011. Unit options awarded to our Named Executive Officers in 2007 vest on May 22, 2011 and expire on May 21, 2017. UARs awarded to our Named Executive Officers in 2007 vest on May 22, 2012 and expire on the same date. Death, disability or retirement of the participant with the approval of the ACG Committee on or after reaching 60 will result in full vesting of all remaining employee awards.

We expect to settle all 2006 LTIP awards in cash or Units at the respective award vesting dates. When UARs become payable, the participant will receive a payment in cash or Units equal to the fair market value of the Units subject to the UARs on the payment date over the fair market value of the Units subject to the UARs on the date of grant, which was $45.35 per Unit.

In addition, each employee participant awarded restricted units or UARs under the 2006 LTIP is entitled to cash distributions. Each participant awarded restricted units is entitled to cash distributions equal to the product of the number of restricted units granted to the participant and the per Unit cash distributions that we paid to our unitholders. Each employee participant awarded UARs is entitled to cash distributions equal to the product of the number of UARs outstanding for the participant and the amount equal to the excess, if any, of the distribution paid per Unit over the grant date distribution per Unit.

The 2006 LTIP may be amended or terminated at any time by the board of directors of EPCO or the ACG Committee; however, any material amendment, such as a material increase in the number of Units available under the plan or a change in the types of awards available under the plan, would require the approval of at least 50% of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2006 LTIP in specified circumstances. The 2006 LTIP is effective until the earlier of December 8, 2016, the time which all available Units under the 2006 LTIP have been delivered to participants or the time of termination of the 2006 LTIP by EPCO or the ACG Committee.

Outstanding Equity Awards at 2007 Fiscal Year-End

The following table presents information concerning each Named Executive Officer's phantom units, restricted units, unexercised unit options and UARs that have not vested at December 31, 2007.

	Option Awards			Unit Awards			
Name	Number of Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number Of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($) (6)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (7)
Jerry E. Thompson							
Phantom units (1)	—	—	—	26,000	996,580	—	—
Restricted units (2)	—	—	—	19,000	728,270	—	—
Unit options (2)	45,000	45.35	5/21/2017	—	—	—	—
UARs (3)	66,152	45.35	5/22/2012	—	—	—	—
William G. Manias							
Phantom units (4)	—	—	—	2,800	107,324	—	—
Restricted units (2)	—	—	—	3,000	114,990	—	—
Unit options (2)	22,000	45.35	5/21/2017	—	—	—	—
UARs (3)	26,461	45.35	5/22/2012	—	—	—	—
J. Michael Cockrell							
Phantom units (5)	—	—	—	—	—	3,100	178,235
Restricted units (2)	—	—	—	4,200	160,986	—	—
Unit options (2)	22,000	45.35	5/21/2017	—	—	—	—
UARs (3)	33,076	45.35	5/22/2012	—	—	—	—
John N. Goodpasture							
Phantom units (5)	—	—	—	—	—	2,800	160,986
Restricted units (2)	—	—	—	3,000	114,990	—	—
Unit options (2)	22,000	45.35	5/21/2017	—	—	—	—
UARs (3)	25,358	45.35	5/22/2012	—	—	—	—
Samuel N. Brown							
Phantom units (5)	—	—	—	—	—	2,700	155,237
Restricted units (2)	—	—	—	3,000	114,990	—	—
Unit options (2)	22,000	45.35	5/21/2017	—	—	—	—
UARs (3)	26,461	45.35	5/22/2012	—	—	—	—

(1) 13,000 of these phantom units vest on April 11, 2008 and the remaining 13,000 phantom units vest on April 11, 2009, subject to earlier vesting on death or disability.

(2) Award vests on May 22, 2011, subject to earlier vesting on death, disability or retirement of the participant with the approval of the ACG Committee on or after reaching age 60.

(3) Award vests on May 22, 2012, subject to earlier vesting on death, disability or retirement of the participant with the approval of the ACG Committee on or after reaching age 60.

(4) Award vests on January 1, 2010, subject to earlier vesting on death or disability.

(5) Award vests on December 31, 2008, subject to earlier vesting on death or disability.

(6) Amount reflects the market value of the number of phantom units and restricted units at December 31, 2007 using the December 31, 2007 Unit price of $38.33 per Unit.

(7) Amount reflects the market value of the award using the maximum potential payout under the 2000 LTIP of 150% at December 31, 2007 and the December 31, 2007 Unit price of $38.33 per Unit.

Option Exercises and Stock Vested Table

The following table presents information concerning vesting of phantom unit awards during 2007 for each of the Named Executive Officers on an aggregate basis.

	Unit Awards	
Name	**Number of Units Acquired On Vesting (#)**	**Value Realized On Vesting ($) (1)**
Jerry E. Thompson (1)	—	577,070
J. Michael Cockrell (2)	—	141,210
Samuel N. Brown (2)	—	84,726
John N. Goodpasture (2)	—	124,265

(1) Amount represents an April 2007 cash payout from the 1999 Plan as a result of the vesting of 13,000 phantom units.

(2) Amount represents vested 2000 LTIP phantom unit awards accrued using a performance percentage of 148% at December 31, 2007, for which cash will be paid out to the Named Executive Officer in March 2008.

Pension Benefits for the 2007 Fiscal Year

There were no payments or other benefits provided in connection with the retirement of Named Executive Officers during 2007.

Nonqualified Deferred Compensation for the 2007 Fiscal Year

During 2007, no Named Executive Officer received deferred compensation (other than incentive awards described elsewhere) on a basis that was not tax-qualified with respect to any defined contribution or other plan.

Employment Arrangements and Potential Payments upon Termination or Change in Control

Employment Agreements

Prior to its acquisition by DCP, the General Partner had entered into employment agreements with certain executive officers. Through December 31, 2006, only four such employment agreements remained in effect, of which three were with Named Executive Officers – Messrs. Cockrell, Goodpasture and Brown. In January 2007, the four remaining employment agreements were supplemented to provide that the employment agreements will automatically terminate on June 1, 2008, in exchange for: (1) a payment that was made in the first quarter of 2007 (the “2007 Award”) to Messrs. Cockrell, Goodpasture and Brown of $489,375, $295,800 and $241,920, respectively; and (ii) if the executive remains employed with EPCO through June 1, 2008, a retention award (the

"Retention Award") in an amount equal to such executive's 2007 Award, due on or before July 31, 2008. Each 2007 Supplement also provides that the executive will receive his Retention Award and COBRA insurance for up to 36 months if he is terminated without cause or because of death, a disability, or resigns as a result of relocation, prior to June 1, 2008. We will reimburse EPCO pursuant to the ASA for the payments and other benefits it provides under the 2007 Supplements. The 2007 Award and Retention Award payments contemplated by the 2007 Supplements replace and supersede the termination payments provided for in the underlying employment agreements. EPCO's practice is to not enter into employment agreements with its executive officers. In order to align the compensation structures of the companies under the EPCO umbrella, the 2007 Supplements converted the existing employment agreements with our executive officers into retention plans.

Termination or Change in Control Payments

Other than as set forth below under the heading "Business Combination with Enterprise Products Partners" and as set forth above under the heading "Employment Agreements," there are currently no outstanding equity incentive plan awards or employment agreements that provide for payments to a Named Executive Officer in event of any termination or change in control; however, the 1999 Plan, 2000 LTIP and 2006 LTIP provide for acceleration of awards in the event of death, disability, and in some cases, retirement. The following table summarizes potential payments that may be made to Named Executive Officers as of December 31, 2007 if specified termination events occur.

Name	Retention Award under 2007 Supplements (1)	Health Care Benefits under 2007 Supplements (1) (2)	Death or Disability Accelerated 1999 Plan Awards (3)	Death, Disability or Retirement Accelerated 2000 LTIP Awards (4)	Death, Disability or Retirement Accelerated 2006 LTIP Awards (5)
Jerry E. Thompson	—	—	996,580	—	728,270
William G. Manias	—	—	107,324	—	114,990
J. Michael Cockrell	489,375	50,679	—	118,451	160,986
John N. Goodpasture	295,800	50,679	—	106,988	114,990
Samuel N. Brown	241,920	50,679	—	103,167	114,990

(1) Named Executive Officer is entitled to benefit if he is terminated without cause or because of death, a disability, or resigns as a result of relocation, prior to June 1, 2008.

(2) Health care benefits are COBRA payments for 36 months as specified in the 2007 Supplement multiplied by an estimated monthly cost of the benefit.

(3) Amount represents the market value of phantom unit awards based on a Unit price of $38.33 at December 31, 2007. Phantom units vest in full in the event of termination due to death or disability.

(4) Named Executive Officer is entitled to this payment in the event of a qualifying termination resulting from death, disability or retirement. These calculations are based on the assumptions that (i) the qualifying event was effective December 31, 2007, (ii) the average of the closing price of a Unit over the ten consecutive trading days immediately preceding December 31, 2007 was $38.21, (iii) the performance percentage applied is 150% and (iv) the performance period completed is two years of the three year term.

(5) Restricted unit, unit option and UAR awards vest in full in the event of termination due to (i) death, (ii) disability or (iii) retirement with the approval of the ACG Committee on or after reaching age 60. Amount represents the market value of the restricted unit awards based on a unit price of $38.33 at December 31, 2007. Unit options and UARs are assigned no market value at December 31, 2007 as a result of the grant date price of $45.35 exceeding the Unit price at December 31, 2007 of $38.33.

Business Combination with Enterprise Products Partners

For any awards under the 1999 Plan and the 2000 LTIP, effective upon a consolidation, merger or combination of the business of Enterprise Products Partners and TEPPCO (a "Business Combination"), as determined by EPCO, in its discretion, prior to the end of the performance period, the award shall terminate in full without payment. Upon such Business Combination, the participant will be granted either restricted units or phantom units (as determined by EPCO in its discretion) under an EPCO long-term incentive plan ("EPCO Grant") equal to the number of long-term incentive units granted by us multiplied by the quotient of (i) the closing sales price of our Units on the effective date of the Business Combination divided by (ii) the closing sales price of an Enterprise Products Partners common unit on that date. For each Named Executive Officer except Mr. Thompson, the EPCO Grant will provide full vesting at the end of its four-year vesting period, provided that the participant is still an employee of EPCO or its affiliates on that date. The four-year vesting period for the EPCO Grant will begin on the date the participant received their award under our plan. For Mr. Thompson, the EPCO Grant will provide, to the extent that such EPCO Grant is awarded prior to any one of the following dates, that one-half will vest on April 11, 2008 and the remaining one-half on April 11, 2009, assuming Mr. Thompson's continuing employment through the vesting period. Each of these EPCO Grants will also provide for earlier vesting upon certain qualifying terminations of employment prior to the end of the vesting period consistent with the form of grant agreement adopted by us with respect to such EPCO long-term incentive plan.

Director Compensation

During 2007, our non-management directors were Messrs. Hutchison, Bracy and Snell. On January 1, 2008, Mr. Daigle, who is not an employee of EPCO or its affiliates, was appointed to our Board. Our General Partner is responsible for compensating these directors for their services. The following table presents information regarding compensation to the non-management directors of our General Partner during 2007.

Director	Fees Earned or Paid in Cash ($)	Unit Awards ($)(3)	Option Awards ($)(4)	All Other Compensation ($)(5)	Total ($)
Michael B. Bracy (1)	65,000	3,507	3,734	758	72,999
Murray H. Hutchison (2)	65,000	3,507	3,734	758	72,999
Richard S. Snell	50,000	3,507	3,734	758	57,999

(1) Chairman of the ACG Committee and Vice Chairman of the Board.

(2) Chairman of the Board.

(3) Amount presented reflects the compensation expense recognized related to phantom units granted during 2007 under the 2006 LTIP (see "– Equity-based compensation" below). On April 30, 2007, the non-executive directors were each awarded 549 phantom units, all of which were outstanding at December 31, 2007. The phantom units are accounted for as liability awards under SFAS 123(R) because they will be settled in cash. These compensation amounts are based on the following assumptions: (i) the closing price of a Unit at December 31, 2007 was $38.33; (ii) the payout percentage is 100%; and (iii) the percentage of the number of days in the period presented compared to the total vesting period. On July 30, 2007, the award agreements for the phantom units granted were amended to provide for settlement in cash. At December 31, 2007, the fair value of phantom units granted to each of Mr. Bracy, Mr. Snell and Mr. Hutchison was $21,043.

(4) Amount presented reflects the compensation expense recognized related to UARs granted during 2007 under the 2006 LTIP (see "– Equity-based compensation" below). On May 2, 2007, the non-executive directors were each awarded 22,075 UARs, all of which were outstanding at December 31, 2007. The UARs are accounted for as liability awards under SFAS 123(R) because they are expected to be settled in cash. The compensation amounts related to UARs are based on the assumptions that (i) the closing price of a Unit at December 31, 2007 was $38.33; and (ii) the payout percentage is 100%. At December 31, 2007, the fair value of UARs granted to each of Mr. Bracy, Mr. Snell and Mr. Hutchison, was $17,239.

(5) Amounts primarily represent quarterly distributions received from phantom unit awards.

Neither we, nor our General Partner, nor EPCO provide any additional compensation to employees of EPCO who serve as directors of our General Partner. Mr. Thompson, who serves as a director, receives no additional compensation for serving as a director.

Cash Compensation

For the year ended December 31, 2007, our standard compensation arrangement for non-employee directors was that each director received $50,000 in cash annually, paid in monthly installments in advance, and the chairman of the Board and chairman of the ACG Committee received an additional $15,000 annually, also paid in monthly installments in advance.

For the year ended December 31, 2008, each non-employee director will receive an additional $25,000 in cash annually, paid in monthly installments in advance.

Equity-Based Compensation

On April 30, 2007, the non-employee members of our Board were each awarded 549 phantom units under the 2006 LTIP. Each phantom unit will pay out in cash on April 30, 2011 or, if earlier, the date the director is no longer serving on our Board, whether by voluntarily resignation or otherwise ("Payment Date"). In addition, for each calendar quarter from the grant date until the Payment Date, each non-employee director will receive a cash payment within such calendar quarter equal to the product of (i) the per Unit cash distributions paid to our unitholders during such calendar quarter, if any, multiplied by (ii) the number of phantom units subject to their grant. Phantom unit awards to non-employee directors are accounted for similar to SFAS 123(R) liability awards.

On May 2, 2007, the non-employee members of our Board were each awarded 22,075 UARs under the 2006 LTIP. The grant date price of the May 2007 UARs was $45.35 per Unit. The UARs will be subject to five year cliff vesting and will vest earlier if the director dies or is removed from, or not re-elected or appointed to, the board for reasons other than his voluntary resignation or unwillingness to serve. When the UARs become payable, the director will receive a payment in cash (or, in the sole discretion of the ACG Committee, Units or a combination of cash and Units) equal to the fair market value of the Units subject to the UARs on the payment date over the fair market value of the Units subject to the UARs on the date of grant. UARs awarded to non-executive directors are accounted for similar to SFAS 123(R) liability awards.

Compensation Committee Interlocks and Insider Participation

The General Partner does not have a compensation committee. The directors of our General Partner do not participate in deliberations concerning the General Partner's executive officer compensation, except for equity awards under our and EPCO's long-term incentive plans. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to compensation of our Named Executive Officers and the specific elements of our compensation package. In order to assist Mr. Duncan and EPCO with compensation decisions, Jerry E. Thompson, our CEO, and the Senior Vice President of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers with the exception of Mr. Thompson. Mr. Duncan then seeks and receives the recommendations of Mr. Thompson. Mr. Duncan, after consulting with the Senior Vice President of Human Resources for EPCO, independently makes compensation decisions with respect to Mr. Thompson. As stated above, the compensation of our Named Executive Officers is paid by EPCO, and we reimburse EPCO for the portion of its compensation expense that is related to our business, pursuant to the ASA. No compensation expense is borne by us with respect to Mr. Duncan.

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

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information based on our outstanding Units as of February 1, 2008, regarding the beneficial ownership of our Units by each person known by us to beneficially own more than 5% of our Units. The amount and nature of beneficial ownership information presented in this table, with respect to Dan L. Duncan, is based on information disclosed in the most recent Schedule 13D filed by each of the beneficial owners listed below on May 18, 2007, and with respect to Arlen B. Cenac, Jr., is based on information disclosed in the most recent Schedule 13G filed by each of the beneficial owners listed below on February 11, 2008.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percentage Owned (2)
Dan L. Duncan: (1)		
Units owned by EPCO: (3) (4)		
Duncan Family Interests, Inc.	8,986,711	9.5%
Units owned by Duncan Family 2000 Trust (5)	53,275	*
Units owned by DD Securities LLC (6)	704,564	*
Units owned by Dan Duncan LLC: (7)		
Units owned by DFI Holdings LLC: (8)		
Units owned by DFI GP Holdings L.P.	2,500,000	2.6%
Units owned by EPE Holdings, LLC: (9)		
Units owned by Enterprise GP Holdings L.P.	4,400,000	4.6%
Units owned directly	47,000	*
Total for Dan L. Duncan	16,691,550	17.6%
Arlen B. Cenac, Jr.: (10)		
Units owned by Cenac Towing Co., Inc.	4,434,005	4.7%
Units owned directly	420,894	*
Total for Arlen B. Cenac, Jr.	4,854,899	5.1%

(1) The address for each beneficial owner listed under Dan L. Duncan is 1100 Louisiana, Suite 1000, Houston, Texas 77002.

(2) An asterisk in the column indicates that the beneficial owner holds less than 1% of the class.

(3) The 8,986,711 Units beneficially owned by EPCO are pledged to the lenders under the EPCO Holdings, Inc. credit facility as security.

(4) As set forth above, Duncan Family Interests, Inc. holds directly 8,986,711 Units. EPCO Holdings, Inc. has shared voting and dispositive power over the 8,986,711 Units beneficially owned by Duncan Family Interests, Inc. Duncan Family Interests, Inc. is a wholly owned subsidiary of EPCO Holdings, Inc., and EPCO Holdings, Inc. is a wholly owned subsidiary of EPCO. Therefore, EPCO and EPCO Holdings, Inc. each have an indirect beneficial ownership interest in the 8,986,711 Units held by Duncan Family Interests, Inc.

(5) Mr. Duncan is deemed to be the beneficial owner of the Units owned by the Duncan Family 2000 Trust, the beneficiaries of which are the shareholders of EPCO.

(6) DD Securities LLC is owned by Mr. Duncan.

(7) Dan Duncan LLC is owned by Mr. Duncan. Dan Duncan LLC is the sole member of DFI Holdings LLC, which is the 1% general partner of DFI GP Holdings L.P. ("DFIGP"), and owns a 4% limited partner interest in DFIGP. Therefore, Dan Duncan LLC has shared voting and dispositive power over all of the 2,500,000 Units owned directly by DFIGP. Additionally, Enterprise GP Holdings' general partner is EPE Holdings, LLC, which is a wholly owned subsidiary of Dan Duncan LLC. As a result, Dan Duncan has shared voting and dispositive power over all of the 4,400,000 Units owned directly by Enterprise GP Holdings.

(8) As set forth above, DFIGP hold directly 2,500,000 Units. DFI Holdings LLC holds no Units directly, but it is the 1% general partner of DFIGP, and as such has voting and dispositive power over the 2,500,000 Units owned directly by DFIGP.

(9) As set forth above, Enterprise GP Holdings holds directly 4,400,000 Units. EPE Holdings, LLC holds no Units directly, but it is the 0.01% general partner of Enterprise GP Holdings, and as such has voting and dispositive power over the 4,400,000 Units owned directly by Enterprise GP Holdings.

(10) The address for each beneficial owner listed under Arlen B. Cenac, Jr. is P.O. Box 2617, Houma, Louisiana, 70361.

Security Ownership of Management

The following table sets forth certain information, as of February 1, 2008, concerning the beneficial ownership of Units by each director and Named Executive Officer of the General Partner and by all current directors and executive officers of the General Partner as a group. This information is based on data furnished by the persons named.

Name	Amount and Nature of Beneficial Ownership (1)	Percentage Owned (2)
Michael B. Bracy	4,000	*
Murray H. Hutchison	—	—
Richard S. Snell	—	—
Donald H. Daigle	—	—
Jerry E. Thompson	35,491	*
Samuel N. Brown	3,000	*
J. Michael Cockrell	9,200	*
John N. Goodpasture	5,000	*
William G. Manias	5,220	*
All directors and current executive officers (consisting of 10 people)	65,181	*

(1) The persons named above have sole voting and investment power over the Units reported.

(2) An asterisk in the column indicates that the beneficial owner holds less than 1% of the class.

Pledge of Interests of our Partnership

The limited partner interests in us that are owned or controlled by EPCO and certain of its affiliates, other than those interests owned by Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an affiliate of EPCO. All of the membership interests in our General Partner and the limited partner interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. If Enterprise GP Holdings were to default under its credit facility, its lender banks could own our General Partner.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of February 1, 2008 regarding the 2006 LTIP, under which our Units are authorized for issuance to EPCO's key employees and to directors of our General Partner through the exercise of Unit options.

Plan Category	Number of Units to be issued upon exercise of outstanding Unit options	Weighted-average exercise price of outstanding Unit options	Number of Units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
2006 LTIP (1)	155,000	$ 45.35	4,782,600
Equity compensation plans not approved by unitholders:			
None	—	—	—
Total for equity compensation plans	155,000	$ 45.35	4,782,600

(1) The 155,000 unit options outstanding at December 31, 2007 are exercisable in 2011. See Note 4 in the Notes to Consolidated Financial Statements for additional information.

The 2006 LTIP may be amended or terminated at any time by the board of directors of EPCO, which is the indirect parent company of our General Partner, or the ACG Committee; however, any material amendment, such as a material increase in the number of Units available under the plan or a change in the types of awards available under the plan, would require the approval of at least 50% of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2006 LTIP in specified circumstances. The 2006 LTIP is effective until December 8, 2016 or, if earlier, the time at which all available Units under the 2006 LTIP have been delivered to participants or the time of termination of the 2006 LTIP by EPCO or the ACG Committee. During 2007, a total of 62,400 restricted unit awards were issued to key employees of EPCO. For additional information regarding the 2006 LTIP and related unit-based awards, see Note 4 in the Notes to Consolidated Financial Statements.

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

We do not have any employees. We are managed by our General Partner, and all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to the ASA or by other service providers. We reimburse EPCO for the allocated costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1 in the Notes to Consolidated Financial Statements).

The following information summarizes our business relationships and transactions with related persons, including EPCO and other affiliates, controlled by Dan L. Duncan, from January 1, 2007 through December 31, 2007. We have also provided information regarding our business relationships and transactions with our unconsolidated affiliates.

For information regarding our related party transactions in general, please read Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this Report.

Interests of the General Partner in the Partnership

We make quarterly cash distributions of all of our available cash, generally defined in our Partnership Agreement as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its reasonable discretion ("Available Cash"). Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as shown in the following table. Effective December 8, 2006, upon approval of our unitholders, our Partnership Agreement was amended and the 50%/50% distribution tier was eliminated in exchange for the issuance of 14,091,275 Units to the General Partner (see Note 1 of the Notes to the Consolidated Financial Statements):

	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 %
Over First Target – Cash distributions greater than $0.325 per Unit	75 %	25 %

During the year ended December 31, 2007, distributions paid to the General Partner totaled $48.3 million, including incentive distributions of $43.3 million.

Relationship with EPCO and Affiliates

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

- EPCO and its consolidated private company subsidiaries;
- Texas Eastern Products Pipeline Company, LLC, our General Partner;
- Enterprise GP Holdings, which owns and controls our General Partner;
- Enterprise Products Partners, which is controlled by affiliates of EPCO, including Enterprise GP Holdings;
- Duncan Energy Partners, which is controlled by affiliates of EPCO; and
- Enterprise Gas Processing, LLC, which is controlled by affiliates of EPCO and is our joint venture partner in Jonah.

Dan L. Duncan directly owns and controls EPCO and through Dan Duncan LLC, owns and controls EPE Holdings, the general partner of Enterprise GP Holdings. Enterprise GP Holdings owns all of the membership interests of our General Partner. The principal business activity of our General Partner is to act as our managing partner. The executive officers of our General Partner are employees of EPCO (see Item 10 of this Report).

We and our General Partner are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO and its consolidated private company subsidiaries and affiliates depend on the cash distributions they receive from our General Partner and other investments to fund their operations and to meet their debt obligations. We paid cash distributions of $48.3 million and $81.9 million during the years ended December 31, 2007 and 2006, to our General Partner.

The limited partner interests in us that are owned or controlled by EPCO and certain of its affiliates, other than those interests owned by Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an affiliate of EPCO. All of the membership interests in our General Partner and the limited partner interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. If Enterprise GP Holdings were to default under its credit facility, its lender banks could own our General Partner.

Unless noted otherwise, our transactions and agreements with EPCO or its affiliates are not on an arm's length basis. As a result, we cannot provide assurance that the terms and provisions of such transactions or agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Administrative Services Agreement

All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the ASA or by other service providers. We and our General Partner, Enterprise Products Partners and its general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner and certain affiliated entities, along with EPCO, are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO provides administrative, management and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.
- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses (direct and indirect) incurred by EPCO which are directly or indirectly related to our business or activities (including EPCO expenses reasonably allocated to us). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.
- EPCO allows us to participate as named insureds in its overall insurance program with the associated costs being allocated to us.

Our operating costs and expenses for the years ended December 31, 2007, 2006 and 2005 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for the years ended December 31, 2007, 2006 and 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

EPCO and its affiliates have no obligation to present business opportunities to us or our Operating Companies, and we and our Operating Companies have no obligation to present business opportunities to EPCO and its affiliates. However, the ASA requires that business opportunities offered to or discovered by EPCO be offered first to certain Enterprise Products Partners' affiliates before they may be pursued by EPCO and its other affiliates or offered to us.

On February 28, 2007, due to the substantial completion of inquires by the FTC into EPCO's acquisition of our General Partner, the parties to the ASA amended it to remove Exhibit B thereto, which had been adopted to address matters the parties anticipated the FTC may consider in its inquiry. Exhibit B had set forth certain separateness and screening policies and procedures among the parties that became inapposite upon the issuance of the FTC's order in connection with the inquiry or were already otherwise reflected in applicable FTC, SEC, NYSE or other laws, standards or governmental regulations.

Transactions between EPCO and affiliates and us

The following table summarizes the related party transactions between EPCO and affiliates and us during the year ended December 31, 2007 (in thousands):

Revenues from EPCO and affiliates:	
Sales of petroleum products (1)	$ 320
Transportation – NGLs (2)	13,153
Transportation – LPGs (3)	5,191
Other operating revenues (4)	1,761
Costs and Expenses from EPCO and affiliates:	
Purchases of petroleum products (5)	61,596
Operating expense (6)	96,947
General and administrative (7)	25,500

(1) Includes sales from LSI to Enterprise Products Partners and certain of its subsidiaries.

(2) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines from Enterprise Products Partners and certain of its subsidiaries.

(3) Includes revenues from LPG transportation on the TE Products pipeline of $5.0 million from Enterprise Products Partners and certain of its subsidiaries and $0.2 million from Energy Transfer Equity, L.P. (see "Relationship with Energy Transfer Equity" below).

(4) Includes other operating revenues on the TE Products pipeline and the Val Verde system from Enterprise Products Partners and certain of its subsidiaries.

(5) Includes TCO purchases of condensate and expenses related to LSI's use of an affiliate of EPCO as a transporter.

(6) Includes operating payroll, payroll related expenses and other operating expenses, including reimbursements related to employee benefits and employee benefit plans, incurred by EPCO in managing us and our subsidiaries in accordance with the ASA. Also includes insurance expense for the year ended December 31, 2007 related to premiums paid by EPCO of $13.6 million for the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, which was obtained through EPCO.

(7) Includes administrative payroll, payroll related expenses and other administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred by EPCO in managing and operating us and our subsidiaries in accordance with the ASA.

The following table summarizes the related party balances with Enterprise Products Partners and its subsidiaries and EPCO and its affiliates at December 31, 2007 (in thousands):

Accounts receivable, related party (1)	$ 492
Accounts payable, related party (2)	33,581

(1) Relates to sales and transportation services provided to Enterprise Products Partners and certain of its subsidiaries and EPCO and certain of its affiliates.

(2) Relates to direct payroll, payroll related costs and other operational related charges from Enterprise Products Partners and certain of its subsidiaries and EPCO and certain of its affiliates.

Sale of Pioneer Plant

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and recommended for approval by the ACG Committee and a fairness opinion was rendered by an investment banking firm. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

Jonah Joint Venture

On August 1, 2006, Enterprise Products Partners (through an affiliate) became our joint venture partner by acquiring an interest in Jonah, the partnership through which we have owned our interest in the Jonah system. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise Products Partners and two representatives approved by us, each with equal voting power. Through December 31, 2007, we have reimbursed Enterprise Products Partners $261.6 million ($152.2 million in 2007 and $109.4 million in 2006) for our share of the Phase V cost incurred by it (including its cost of capital incurred prior to the formation of the joint venture of $1.3 million). At December 31, 2007, we had a payable to Enterprise Products Partners for costs incurred of $9.9 million. At December 31, 2007, we had a receivable from Jonah of $6.0 million for distributions and operating expenses. During the year ended December 31, 2007, we received distributions from Jonah of $100.0 million, which included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the year ended December 31, 2007, we invested $187.5 million in Jonah. During the year ended December 31, 2007, Jonah paid distributions of $9.7 million to the affiliate of Enterprise Products Partners that is our joint venture partner. For additional information, please see "Items 1 and 2. Business and Properties – Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs."

We have agreed to indemnify Enterprise Products Partners from any and all losses, claims, demands, suits, liability, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the formation of the Jonah joint venture, Jonah's ownership or operation of the Jonah system prior to the effective date of the joint venture, and any environmental activity, or violation of or liability under environmental laws arising from or related to the condition of the Jonah system prior to the effective date of the joint venture. In general, a claim for indemnification cannot be filed until the losses suffered by Enterprise Products Partners exceed $1.0 million, and the maximum potential amount of future payments under the indemnity is limited to $100.0 million. However, if certain representations or warranties are breached, the maximum potential amount of future payments under the indemnity is capped at $207.6 million. All indemnity payments are net of insurance recoveries that Enterprise Products Partners may receive from third-party insurers. We carry insurance coverage that may offset any payments required under the indemnity. We do not expect that these indemnities will have a material adverse effect on our financial position, results of operations or cash flows.

Sale of General Partner to Enterprise GP Holdings; Relationship with Energy Transfer Equity

On May 7, 2007, all of the membership interests in our General Partner, together with 4,400,000 of our Units, were sold by DFIGP to Enterprise GP Holdings, a publicly traded partnership also controlled indirectly by Dan L Duncan. As of May 7, 2007, Enterprise GP Holdings owns and controls the 2% general partner interest in us and has the right (through its 100% ownership of our General Partner) to receive the incentive distribution rights associated with the general partner interest. Enterprise GP Holdings, DFIGP and other entities controlled by Mr. Duncan own 16,691,550 of our Units.

Concurrently with the acquisition of our General Partner, Enterprise GP Holdings acquired non-controlling ownership interests in Energy Transfer Equity, L.P. ("Energy Transfer Equity") and LE GP, LLC ("ETE GP"), the general partner of Energy Transfer Equity. Following the transaction, Enterprise GP Holdings owns approximately 34.9% of the membership interests in ETE GP and 38,976,090 common units of Energy Transfer Equity representing approximately 17.6% of the outstanding limited partner interests in Energy Transfer Equity.

Other Transactions

On January 23, 2007, we sold a 10-mile, 18-inch diameter segment of pipeline to a subsidiary of Enterprise Products Partners for approximately $8.0 million. These assets were part of our Downstream Segment and had a net book value of approximately $2.5 million. The sales proceeds were used to fund construction of a replacement pipeline in the area, in which the new pipeline provides greater operational capability and flexibility. We recognized a gain of approximately $5.5 million on this transaction (see Note 10 in the Notes to Consolidated Financial Statements).

In June 2007, we purchased 300,000 barrels of propane linefill from a subsidiary of Enterprise Products Partners for approximately $14.4 million. In November 2007, we purchased 100,000 barrels of butane inventory from an affiliate of Enterprise Products Partners for approximately $8.0 million.

Acquisition of Marine Transportation Business

On February 1, 2008, we entered the marine transportation business through the purchase of 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements from Cenac Towing Co., Inc., Cenac Offshore, L.L.C. (collectively, "Cenac") and Mr. Arlen B. Cenac, Jr., the sole owner of Cenac Towing Co., Inc. and Cenac Offshore (collectively, the "Cenac Sellers") for approximately $443.8 million, consisting of approximately $256.6 million in cash and approximately 4.85 million newly issued Units, representing approximately 5% of our outstanding Units. Additionally, we assumed $63.2 million of Cenac's long-term debt. For additional information regarding our marine transportation business, please refer to "Item 1. Business —Marine Transportation Segment—Barge Transportation of Petroleum Products." In connection with the acquisition, we entered into a transitional operating agreement with the Cenac Sellers under which the purchased assets will continue to be operated by them for up to two years. We will reimburse the Cenac Sellers for their cost of providing the services under the transitional operating agreement and pay a service fee of $500,000 per year. We are obligated to indemnify the Cenac Sellers for third party claims and damages that arise from the their operation of the purchased assets, unless such claims or damages arise from their gross negligence or willful misconduct or other specified exceptions apply.

Review and Approval of Transactions with Related Parties

As further described below, our Partnership Agreement sets forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the General Partner or the ACG Committee. In submitting a matter to the ACG Committee, the Board on behalf of the General Partner, the Operating Companies or us may charge the committee with reviewing the transaction and providing the Board a recommendation, or it may delegate to the committee the power to approve the matter.

The ACG Committee Charter provides that the ACG Committee is established to review and approve related party transactions:

- for which Board approval is required by our management authorization policy, as such policy may be amended from time to time;
- where an officer or director of the General Partner or any of our subsidiaries is a party;
- when requested to do so by management or the Board; or
- pursuant to our Partnership Agreement or the limited liability company agreement of the General Partner, as such agreements may be amended from time to time.

The ASA governs numerous day-to-day transactions between us and our subsidiaries and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs for those services. The ACG Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation. Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, may be subject to our General Partner's written internal review and approval policies and procedures. These internal policies and procedures, which apply to related party transactions as well as transactions with unrelated parties, specify thresholds for our General Partner's officers and managers to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements. The specified thresholds for some categories of transactions are less than $120,000 and for others are substantially greater.

Under our Partnership Agreement, unless otherwise expressly provided therein or in the partnership agreements of our Operating Companies, whenever a potential conflict of interest exists or arises between our General Partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by the General Partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our Partnership Agreement, any of the operating partnership agreements or any agreement contemplated by such agreements, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the Partnership Agreement is deemed to be, fair and reasonable to us; *provided* that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by "Special Approval" (i.e., by a majority of the members of the ACG Committee), or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

In connection with its resolution of any conflict of interest, our Partnership Agreement authorizes the ACG Committee (in connection with Special Approval) to consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);
- any customary or accepted industry practices and any customary or historical dealings with a particular person;
- any applicable generally accepted accounting or engineering practices or principles; and
- such additional factors as the ACG Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and work performed by the ACG Committee with respect to a transaction varies depending upon the nature of the transaction and the scope of the committee's charge. Examples of functions the ACG Committee may, as it deems appropriate, perform in the course of reviewing a transaction include (but are not limited to):

- assessing the business rationale for the transaction;
- reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;
- assessing the effect of the transaction on our earnings and distributable cash flow per Unit, and on our results of operations, financial condition, properties or prospects;
- conducting due diligence, including by interviews and discussions with management and other representatives and by reviewing transaction materials and findings of management and other representatives;
- considering the relative advantages and disadvantages of the transactions to the parties;
- engaging third party financial advisors to provide financial advice and assistance, including by providing fairness opinions if requested;
- engaging legal advisors;
- evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in the Partnership Agreement requires the ACG Committee to consider the interests of any person other than the Partnership. In the absence of bad faith by the ACG Committee or our General Partner, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the ACG Committee or our General Partner with respect to such matter are conclusive and binding on all persons (including all of our partners) and do not constitute a breach of the Partnership Agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in the Partnership Agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. The Partnership Agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the ACG Committee or our General Partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Relationships with Unconsolidated Affiliates

The following table summarizes the related party transactions between Centennial, MB Storage, Seaway or Jonah, on one hand, and us, on the other hand, during the year ended December 31, 2007 (in thousands):

	For Year Ended December 31, 2007
Revenues from unconsolidated affiliates:	
Other operating revenues (1)	$ 351
Costs and Expenses from unconsolidated affiliates:	
Purchases of petroleum products (2)	5,493
Operating expense (3)	8,736

(1) Includes management fees and rental revenues.

(2) Includes pipeline transportation expense.

(3) Includes rental expense and other operating expense.

The following table summarizes the related party balances with Centennial, Seaway and Jonah at December 31, 2007 (in thousands):

	December 31, 2007
Accounts receivable, related parties (1)	$6,033
Accounts payable, related parties (2)	5,399

(1) Receivable from Jonah which relates to payroll related costs and other operational expenses we charge Jonah, partially offset by our purchases from Jonah.

(2) Payable relates to direct transportation and other services provided by Centennial and Seaway and advances from Seaway for operating expenses.

For additional discussion of contributions to and distributions from our unconsolidated affiliates, see Note 9 in the Notes to Consolidated Financial Statements.

Director Independence

Messrs. Bracy, Hutchison, Daigle and Snell have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and certain transactions, relationships or arrangements considered by the Board in making its independence determinations, please refer to Item 10. Directors, Executive Officers and Corporate Governance, "—Partnership Management”, “—Corporate Governance” and “—Audit, Conflicts and Governance Committee”, which are incorporated into this item by reference.

Item 14. *Principal Accounting Fees and Services*

Appointment of Independent Registered Public Accountant

The ACG Committee has appointed Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively “Deloitte & Touche”) as our principal accountant to conduct the audit of our financial statements for the fiscal year ended December 31, 2007.

Audit Fees

The aggregate fees billed by Deloitte & Touche for professional services rendered for the audit of our financial statements for the years ended December 31, 2007 and 2006, and for other services rendered during those periods on our behalf were as follows (in thousands):

Type of Fee	For Year Ended December 31, 2007	For Year Ended December 31, 2006
Audit Fees (1)	$ 1,947	$ 1,706
Audit Related Fees (2)	—	—
Tax Fees (3)	264	107
All Other Fees (4)	—	—
Total	$ 2,211	$ 1,813

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

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

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

(4) All other fees represent amounts we were billed in each of the years presented for services not classified under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last two years.

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

Pursuant to its charter, the ACG Committee is responsible for pre-approving all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed for us by our independent registered public accountants. On April 30, 2007, the ACG Committee pre-approved Deloitte & Touche and all related fees to conduct the audit of our financial statements for the year ending December 31, 2007.

Additionally, all permitted non-audit engagements with Deloitte & Touche have been reviewed and approved by the ACG Committee, pursuant to pre-approval policies and procedures established by the ACG Committee. In connection with its oversight responsibilities, the ACG Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial “pre-approved” fee amount). As part of these discussions, the ACG Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche’s pre-approved amounts compared to actual fees billed for each of the primary service categories. The Committee’s pre-approval process helps to ensure the independence of our registered public accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. *Exhibits, Financial Statement Schedules.*

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

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

(2) Financial Statement Schedules: (i) Consolidated Financial Statements of Jonah Gas Gathering Company and Subsidiary as of and for the years ended December 31, 2007 and 2006 and (ii) Financial Statements of LDH Energy Mont Belvieu L.P. (formerly Mont Belvieu Storage Partners, L.P.) as of and for the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005.

(3) Exhibits.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated December 8, 2006 (Filed as Exhibit 3 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on December 13, 2006).
3.3	Amended and Restated Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC (Filed as Exhibit 3 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 10, 2007 and incorporated herein by reference).
3.4	First Amendment to Fourth Amended and Restated Partnership Agreement of TEPPCO Partners, L.P. dated as of December 27, 2007 (Filed as Exhibit 3.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 28, 2007 and incorporated herein by reference).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.3	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.4	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union

Exhibit Number	Description
	National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
4.6	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
4.7	Full Release of Guarantee dated as of July 31, 2006 by Wachovia Bank, National Association, as trustee, in favor of Jonah Gas Gathering Company (Filed as Exhibit 4.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2006 and incorporated herein by reference).
4.8	Indenture, dated as of May 14, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 99.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 15, 2007 and incorporated herein by reference).
4.9	First Supplemental Indenture, dated as of May 18, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 4.2 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 18, 2007 and incorporated herein by reference).
4.10	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. , Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 4.2 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
4.11	Fourth Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.3 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
4.12	Fourth Amendment to Amended and Restated Credit Agreement and Waiver, dated as of June 29, 2007, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank

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Exhibit Number	Description
	of Scotland Plc, as Co-Documentation. (Filed as Exhibit 4.14 to Form 10-Q of TEPPCO Partners, L.P. (Commision File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.1+	Duke Energy Corporation Executive Savings Plan (Filed as Exhibit 10.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.2+	Duke Energy Corporation Executive Cash Balance Plan (Filed as Exhibit 10.8 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.3+	Duke Energy Corporation Retirement Benefit Equalization Plan (Filed as Exhibit 10.9 to Form 10-K for TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.4+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan executed on March 8, 1994 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1994 and incorporated herein by reference).
10.5+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan, Amendment 1, effective January 16, 1995 (Filed as Exhibit 10.12 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 1999 and incorporated herein by reference).
10.6+	Form of Employment Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth, John N. Goodpasture, Leonard W. Mallett, Stephen W. Russell, C. Bruce Shaffer, and Barbara A. Carroll (Filed as Exhibit 10.20 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
10.7	Services and Transportation Agreement between TE Products Pipeline Company, Limited Partnership and Fina Oil and Chemical Company, BASF Corporation and BASF Fina Petrochemical Limited Partnership, dated February 9, 1999 (Filed as Exhibit 10.22 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.8	Call Option Agreement, dated February 9, 1999 (Filed as Exhibit 10.23 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.9+	Form of Employment and Non-Compete Agreement between the Company and J. Michael Cockrell effective January 1, 1999 (Filed as Exhibit 10.29 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.10+	Texas Eastern Products Pipeline Company Non-employee Directors Unit Accumulation Plan, effective April 1, 1999 (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.11+	Texas Eastern Products Pipeline Company Non-employee Directors Deferred Compensation Plan, effective November 1, 1999 (Filed as Exhibit 10.31 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.12+	Texas Eastern Products Pipeline Company Phantom Unit Retention Plan, effective August 25, 1999 (Filed as Exhibit 10.32 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.13+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Amendment and Restatement, effective January 1, 2000 (Filed as Exhibit 10.28 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.14+	TEPPCO Supplemental Benefit Plan, effective April 1, 2000 (Filed as Exhibit 10.29 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).

Exhibit Number	Description
10.15	Contribution, Assignment and Amendment Agreement among TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., Texas Eastern Products Pipeline Company, LLC, and TEPPCO GP, Inc., dated July 26, 2001 (Filed as Exhibit 3.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2001 and incorporated herein by reference).
10.16	Certificate of Formation of TEPPCO Colorado, LLC (Filed as Exhibit 3.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1998 and incorporated herein by reference).
10.17	Unanimous Written Consent of the Board of Directors of TEPPCO GP, Inc. dated February 13, 2002 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.18	Purchase and Sale Agreement between Burlington Resources Gathering Inc. as Seller and TEPPCO Partners, L.P., as Buyer, dated May 24, 2002 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.19	Agreement of Limited Partnership of Val Verde Gas Gathering Company, L.P., dated May 29, 2002 (Filed as Exhibit 10.48 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.20+	Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan, effective June 1, 2002 (Filed as Exhibit 10.49 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.21+	Amended and Restated TEPPCO Supplemental Benefit Plan, effective November 1, 2002 (Filed as Exhibit 10.44 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.22+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Second Amendment and Restatement, effective January 1, 2003 (Filed as Exhibit 10.45 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.23+	Amended and Restated Texas Eastern Products Pipeline Company, LLC Management Incentive Compensation Plan, effective January 1, 2003 (Filed as Exhibit 10.46 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.24+	Amended and Restated TEPPCO Retirement Cash Balance Plan, effective January 1, 2002 (Filed as Exhibit 10.47 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.25	Formation Agreement between Panhandle Eastern Pipe Line Company and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, dated as of August 10, 2000 (Filed as Exhibit 10.48 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.26	Amended and Restated Limited Liability Company Agreement of Centennial Pipeline LLC dated as of August 10, 2000 (Filed as Exhibit 10.49 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.27	Guaranty Agreement, dated as of September 27, 2002, between TE Products Pipeline Company, Limited Partnership and Marathon Ashland Petroleum LLC for Note Agreements of Centennial Pipeline LLC (Filed as Exhibit 10.50 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.28	LLC Membership Interest Purchase Agreement By and Between CMS Panhandle Holdings, LLC, As Seller and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, Severally as Buyers, dated February 10, 2003

Exhibit Number	Description
	(Filed as Exhibit 10.51 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.29	Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders dated as of October 21, 2004 ($600,000,000 Revolving Facility) (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of October 21, 2004 and incorporated herein by reference).
10.30+	Texas Eastern Products Pipeline Company Amended and Restated Non-employee Directors Deferred Compensation Plan, effective April 1, 2002 (Filed as Exhibit 10.42 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.31+	Texas Eastern Products Pipeline Company Second Amended and Restated Non-employee Directors Unit Accumulation Plan, effective January 1, 2004 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.32+	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan, dated February 23, 2005, but effective as of January 1, 2005 (Filed as Exhibit 10.4 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
10.33	First Amendment to Amended and Restated Credit Agreement, dated as of February 23, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A. as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 24, 2005 and incorporated herein by reference).
10.34+	Supplemental Agreement to Employment and Non-Compete Agreement between the Company and J. Michael Cockrell dated as of February 23, 2005 (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.35+	Supplemental Form Agreement to Form of Employment Agreement between the Company and John N. Goodpasture, Stephen W. Russell, C. Bruce Shaffer and Barbara A. Carroll dated as of February 23, 2005 (Filed as Exhibit 10.3 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.36+	Supplemental Form Agreement to Form of Employment and Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth and Leonard W. Mallett dated as of February 23, 2005 (Filed as Exhibit 10.4 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.37+	Amendments to the TEPPCO Retirement Cash Balance Plan and the TEPPCO Supplemental Benefit Plan dated as of May 27, 2005 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
10.38	Second Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A., as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of December 13, 2005 and incorporated herein by reference).
10.39+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan Notice of 2006 Award (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2006 and incorporated herein by reference).

Exhibit Number	Description
10.40+	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan Notice of 2006 Award (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2006 and incorporated herein by reference).
10.41	Third Amendment to Amended and Restated Credit Agreement, dated as of July 31, 2006, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation Agents (Filed as Exhibit 10.3 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.42	Amended and Restated Partnership Agreement of Jonah Gas Gathering Company dated as of August 1, 2006 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.43	Contribution Agreement among TEPPCO GP, Inc., TEPPCO Midstream Companies, L.P. and Enterprise Gas Processing, LLC dated as of August 1, 2006 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.44	Transaction Agreement by and between TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC dated as of September 5, 2006 (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed September 12, 2006 and incorporated herein by reference).
10.45	Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2007, but effective as of February 5, 2007 (Filed as Exhibit 10.18 to Current Report on Form 8-K of Duncan Energy Partners L.P. (Commission File No. 1-33266) filed February 5, 2007 and incorporated herein by reference).
10.46+	Form of Supplemental Agreement to Employment Agreement between Texas Eastern Products Pipeline Company, LLC and assumed by EPCO, Inc., and John N. Goodpasture, Samuel N. Brown and J. Michael Cockrell (Filed as Exhibit 10.62 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2006 and incorporated herein by reference).
10.47+	Form of Retention Agreement (Filed as Exhibit 10.63 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2006 and incorporated herein by reference).
10.48	Second Amended and Restated Agreement of Limited Partnership of TCTM, L.P. by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007 (Filed as Exhibit 10.65 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2006 and incorporated herein by reference).
10.49	First Amendment to the Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated February 28, 2007 (Filed as Exhibit 10.8 to Form 10-K of Enterprise Products Partners L.P. (Commission File No. 1-14323) for the year ended December 31, 2006 and incorporated herein by reference).

Exhibit Number	Description
10.50	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (Filed as Exhibit 99.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 18, 2007 and incorporated herein by reference).
10.51	Company Agreement of TE Products Pipeline Company, LLC by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of June 30, 2007 (Filed as Exhibit 3.2 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
10.52	Company Agreement of TEPPCO Midstream Companies, LLC by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of June 30, 2007 (Filed as Exhibit 10.5 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.53	Second Amendment to Fourth Amended and Restated Administrative Services Agreement dated August 7, 2007, but effective as of May 7, 2007 (Filed as Exhibit 10.1 to Form 10-Q of Duncan Energy Partners L.P. (Commission File No. 1-33266) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.54	Assignment, Assumption and Amendment No. 2 to Guaranty Agreement, dated as of May 21, 2007, by and among TE Products Pipeline Company, Limited Partnership, Marathon Petroleum Company, LLC and Marathon Oil Corporation (Filed as Exhibit 10.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.55+	Form of TPP Employee Unit Appreciation Right Grant of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 25, 2007 and incorporated herein by reference).
10.56+	Form of TPP Director Unit Appreciation Right Grant of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2007 and incorporated herein by reference).
10.57+	Form of Phantom Unit Grant for Directors, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. TPP Long-Term Incentive Plan (Filed as Exhibit 10.3 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.58+	Form of TPP Employee Restricted Unit Grant, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2007 and incorporated herein by reference).
10.59+	Form of TPP Employee Option Grant, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2007 and incorporated herein by reference).
10.60	Fifth Amendment to Amended and Restated Credit Agreement, dated as of December 18, 2007, by and among TEPPCO Partners, L.P., the Borrower, the several banks and other financial institutions party thereto and SunTrust Bank, as the administrative agent for the lenders (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 21, 2007 and incorporated herein by reference).
10.61	Term Credit Agreement dated as of December 21, 2007, by and among TEPPCO Partners, L.P., the banks and other financial institutions party thereto and SunTrust Bank, as the administrative agent for the lenders (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 28, 2007 and incorporated herein by reference).

Exhibit Number	Description
10.62	Amended and Restated Guaranty Agreement, dated as of January 17, 2008, by and among The Prudential Insurance Company of America, TCTM, L.P., TEPPCO Midstream Companies, LLC, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed January 24, 2008 and incorporated herein by reference).
10.63	Asset Purchase Agreement, dated February 1, 2008, by and among TEPPCO Marine Services, LLC, TEPPCO Partners, L.P., Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (Filed as Exhibit 2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed February 7, 2008 and incorporated herein by reference).
10.64	Transitional Operating Agreement, dated February 1, 2008, by and among TEPPCO Marine Services, LLC, Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed February 7, 2008 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
16	Letter from KPMG LLP to the Securities and Exchange Commission dated April 11, 2006 (Filed as Exhibit 16.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed April 11, 2006 and incorporated herein by reference).
21*	Subsidiaries of TEPPCO Partners, L.P.
23.1*	Consent of Deloitte & Touche LLP – TEPPCO Partners, L.P. and subsidiaries.
23.2*	Consent of Deloitte & Touche LLP – Jonah Gas Gathering Company and subsidiary.
23.3*	Consent of Deloitte & Touche LLP – LDH Energy Mont Belvieu L.P. (formerly Mont Belvieu Storage Partners, L.P.)
23.4*	Consent of KPMG LLP.
24*	Powers of Attorney.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.

\+ A management contract or compensation plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

TEPPCO Partners, L.P.

	By:	/s/ JERRY E. THOMPSON
Date: February 28, 2008		Jerry E. Thompson, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, General Partner
	By:	/s/ WILLIAM G. MANIAS
Date: February 28, 2008		William G. Manias, Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, General Partner

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

Signature	Title	Date
/s/ JERRY E. THOMPSON Jerry E. Thompson	President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC (Principal Executive Officer)	February 28, 2008
/s/ WILLIAM G. MANIAS William G. Manias	Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC (Principal Financial and Accounting Officer)	February 28, 2008
MICHAEL B. BRACY* Michael B. Bracy	Director of Texas Eastern Products Pipeline Company, LLC	February 28, 2008
RICHARD S. SNELL* Richard S. Snell	Director of Texas Eastern Products Pipeline Company, LLC	February 28, 2008
MURRAY H. HUTCHISON* Murray H. Hutchison	Chairman of the Board of Texas Eastern Products Pipeline Company, LLC	February 28, 2008
DONALD H. DAIGLE* Donald H. Daigle	Director of Texas Eastern Products Pipeline Company, LLC	February 28, 2008

* Signed on behalf of the Registrant and each of these persons pursuant to Powers of Attorney filed as Exhibit 24:

By: /s/ WILLIAM G. MANIAS
(William G. Manias, Attorney-in-fact)

TEPPCO PARTNERS, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries (the “Partnership”) as of December 31, 2007 and 2006, and the related consolidated statements of income and comprehensive income, consolidated cash flows and consolidated partners’ capital for each of the two years in the period ended December 31, 2007. These consolidated financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion on the Partnership’s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated statements of income and comprehensive income, partners' capital, and cash flows of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2005. 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 audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

KPMG LLP

Houston, Texas
February 28, 2006, except for the effects of discontinued operations,
as discussed in Note 10, which is as of June 1, 2006

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23	$ 70
Accounts receivable, trade (net of allowance for doubtful accounts of $125 and $100)	1,381,871	852,816
Accounts receivable, related parties	6,525	11,788
Inventories	80,299	72,193
Other	47,271	29,843
Total current assets	1,515,989	966,710
Property, plant and equipment, at cost (net of accumulated depreciation of $582,225 and $509,889)	1,793,634	1,642,095
Equity investments	1,146,995	1,039,710
Intangible assets	164,681	185,410
Goodwill	15,506	15,506
Other assets	113,252	72,661
Total assets	$ 4,750,057	$ 3,922,092
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Senior notes	$ 353,976	$ —
Accounts payable and accrued liabilities	1,413,447	855,306
Accounts payable, related parties	38,980	34,461
Accrued interest	35,491	35,523
Other accrued taxes	20,483	14,482
Other	84,848	36,776
Total current liabilities	1,947,225	976,548
Long-term debt:		
Senior notes	721,545	1,113,287
Junior subordinated notes	299,538	—
Other long-term debt	490,000	490,000
Total long-term debt	1,511,083	1,603,287
Deferred tax liability	—	652
Other liabilities and deferred credits	27,122	19,461
Other liabilities, related party	—	1,814
Commitments and contingencies		
Partners' capital:		
Limited partners' interests:		
Limited partner units (89,849,132 and 89,804,829 units outstanding)	1,394,812	1,405,559
Restricted limited partner units (62,400 and 0 units outstanding)	338	—
General partner's interest	(87,966)	(85,655)
Accumulated other comprehensive (loss) income	(42,557)	426
Total partners' capital	1,264,627	1,320,330
Total liabilities and partners' capital	$ 4,750,057	$ 3,922,092

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED INCOME AND COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31, 2007	2006	2005
Operating revenues:			
Sales of petroleum products	$ 9,147,104	$ 9,080,516	$ 8,061,808
Transportation – Refined products	170,231	152,552	144,552
Transportation – LPGs	101,076	89,315	96,297
Transportation – Crude oil	45,952	38,822	37,614
Transportation – NGLs	46,542	43,838	43,915
Gathering – Natural gas	61,634	123,933	152,797
Other	85,521	78,509	68,051
Total operating revenues	9,658,060	9,607,485	8,605,034
Costs and expenses:			
Purchases of petroleum products	9,017,109	8,967,062	7,986,438
Operating expense	191,697	203,015	185,777
Operating fuel and power	61,458	57,450	48,972
General and administrative	33,657	31,348	33,143
Depreciation and amortization	105,225	108,252	110,729
Taxes – other than income taxes	18,012	17,983	20,610
Gains on sales of assets	(18,653)	(7,404)	(668)
Total costs and expenses	9,408,505	9,377,706	8,385,001
Operating income	249,555	229,779	220,033
Other income (expense):			
Interest expense – net	(101,223)	(86,171)	(81,861)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	59,628	—	—
Equity earnings	68,755	36,761	20,094
Interest income	1,676	2,077	687
Other income – net	1,346	888	448
Income before provision for income taxes	279,737	183,334	159,401
Provision for income taxes	557	652	—
Income from continuing operations	279,180	182,682	159,401
Income from discontinued operations	—	1,497	3,150
Gain on sale of discontinued operations	—	17,872	—
Discontinued operations	—	19,369	3,150
Net income	$ 279,180	$ 202,051	$ 162,551
Changes in fair values of interest rate cash flow hedges and treasury locks	(23,668)	(248)	—
Changes in fair values of crude oil cash flow hedges	(19,382)	730	11
Changes in plan assets and projected benefit obligation	(67)	—	—
Comprehensive income	$ 236,063	$ 202,533	$ 162,562

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED INCOME AND COMPREHENSIVE INCOME – (Continued)
(Dollars in thousands, except per Unit amounts)

	For Year Ended December 31,		
	2007	2006	2005
Net Income Allocation:			
Limited Partner Unitholders:			
Income from continuing operations	$ 233,193	$ 130,483	$ 112,744
Income from discontinued operations	—	13,835	2,228
Total Limited Partner Unitholders net income allocation	233,193	144,318	114,972
General Partner:			
Income from continuing operations	45,987	52,199	46,657
Income from discontinued operations	—	5,534	922
Total General Partner net income allocation	45,987	57,733	47,579
Total net income allocated	$ 279,180	$ 202,051	$ 162,551
Basic and diluted net income per Limited Partner Unit:			
Continuing operations	$ 2.60	$ 1.77	$ 1.67
Discontinued operations	—	0.19	0.04
Basic and diluted net income per Limited Partner Unit	$ 2.60	$ 1.96	$ 1.71
Weighted average limited partner units outstanding	89,850	73,657	67,397

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31, 2007	2006	2005
Operating activities:			
Net income	$ 279,180	$ 202,051	$ 162,551
Adjustments to reconcile net income to cash provided by continuing operating activities:			
Income from discontinued operations	—	(19,369)	(3,150)
Deferred income taxes	(679)	652	—
Depreciation and amortization	105,225	108,252	110,729
Amortization of deferred compensation	830	—	—
Earnings in equity investments	(68,755)	(36,761)	(20,094)
Distributions from equity investments	122,900	63,483	37,085
Gains on sales of assets	(18,653)	(7,404)	(668)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	(59,628)	—	—
Loss on early extinguishment of debt	1,356	—	—
Non-cash portion of interest expense	1,441	1,676	1,624
Net effect of changes in operating accounts	(12,645)	(41,028)	(37,354)
Net cash provided by continuing operating activities	350,572	271,552	250,723
Net cash provided by discontinued operations	—	1,521	3,782
Net cash provided by operating activities	350,572	273,073	254,505
Investing activities:			
Proceeds from sales of assets	27,784	51,558	510
Proceeds from sale of ownership interest	137,326	—	—
Purchase of assets	(12,909)	(20,473)	(112,231)
Investment in Mont Belvieu Storage Partners, L.P.	—	(4,767)	(4,233)
Investment in Centennial Pipeline LLC	(11,081)	(2,500)	—
Investment in Jonah Gas Gathering Company	(187,547)	(121,035)	—
Capitalized costs incurred to develop identifiable intangible assets	(3,283)	—	—
Cash paid for linefill on assets owned	(39,418)	(6,453)	(14,408)
Capital expenditures	(228,272)	(170,046)	(220,553)
Net cash used in investing activities	(317,400)	(273,716)	(350,915)
Financing activities:			
Proceeds from revolving credit facility	1,305,750	924,125	657,757
Repayments on revolving credit facility	(1,305,750)	(840,025)	(604,857)
Redemption of portion of 7.51% Senior Notes	(36,138)	—	—
Issuance of Limited Partner Units, net	1,696	195,060	278,806
Issuance of Junior Subordinated Notes	299,517	—	—
Debt issuance costs	(4,052)	—	(498)
Proceeds from termination of treasury locks	1,443	—	—
Payment for termination of interest rate swap	(1,235)	—	—
Distributions paid	(294,450)	(278,566)	(251,101)
Net cash provided by (used in) financing activities	(33,219)	594	80,107
Net change in cash and cash equivalents	(47)	(49)	(16,303)
Cash and cash equivalents, January 1	70	119	16,422
Cash and cash equivalents, December 31	$ 23	$ 70	$ 119

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

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

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive (Loss) Income	Total
Balance, December 31, 2004	62,998,554	$ (35,881)	$ 1,046,984	$ —	$ 1,011,103
Issuance of Limited Partner Units, net	6,965,000	—	278,806	—	278,806
Changes in fair values of crude oil cash flow hedges	—	—	—	11	11
2005 net income allocation	—	47,579	114,972	—	162,551
2005 cash distributions	—	(73,185)	(177,916)	—	(251,101)
Balance, December 31, 2005	69,963,554	(61,487)	1,262,846	11	1,201,370
Issuance of Limited Partner Units, net	5,750,000	—	195,060	—	195,060
Issuance of Limited Partner Units to General Partner	14,091,275	—	—	—	—
2006 net income allocation	—	57,733	144,318	—	202,051
2006 cash distributions	—	(81,901)	(196,665)	—	(278,566)
Changes in fair values of crude oil cash flow hedges	—	—	—	730	730
Changes in fair values of interest rate cash flow hedges	—	—	—	(248)	(248)
Adjustment to initially apply SFAS No. 158	—	—	—	(67)	(67)
Balance, December 31, 2006	89,804,829	(85,655)	1,405,559	426	1,320,330
Issuance of restricted units under the 2006 LTIP	62,400	—	—	—	—
Limited Partner Units issued in connection with the Employee Unit Purchase Plan	4,507	—	180	—	180
Limited Partner Units issued in connection with Distribution Reinvestment Plan	39,796	—	1,516	—	1,516
2007 net income allocation	—	45,987	233,193	—	279,180
2007 cash distributions	—	(48,298)	(246,152)	—	(294,450)
Non-cash contribution	—	—	426	—	426
Amortization of equity awards	—	—	428	—	428
Changes in fair values of crude oil cash flow hedges	—	—	—	(19,382)	(19,382)
Changes in fair values of interest rate cash flow hedges and treasury locks	—	—	—	(23,668)	(23,668)
Pension benefit SFAS No. 158 adjustment	—	—	—	67	67
Balance, December 31, 2007	89,911,532	$ (87,966)	$ 1,395,150	$ (42,557)	$ 1,264,627

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. PARTNERSHIP ORGANIZATION

Partnership Organization

TEPPCO Partners, L.P. (the “Partnership”) is a publicly traded Delaware limited partnership and our limited partner units are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “TPP.” As used in this Report, “we,” “us,” “our,” the “Partnership” and “TEPPCO” mean TEPPCO Partners, L.P. and, where the context requires, include our subsidiaries. At formation in March 1990, we completed an initial public offering of 26,500,000 units representing limited partner interests (“Units”) at $10.00 per Unit.

Through June 29, 2007, we operated through TE Products Pipeline Company, Limited Partnership, TCTM, L.P. (“TCTM”) and TEPPCO Midstream Companies, L.P. On June 30, 2007, each of TE Products Pipeline Company, Limited Partnership and TEPPCO Midstream Companies, L.P. separately converted into Texas limited partnerships and immediately thereafter each merged into separate newly-formed Texas limited liability companies that had no business operations prior to the merger. The resulting limited liability companies are called TE Products Pipeline Company, LLC (“TE Products”) and TEPPCO Midstream Companies, LLC (“TEPPCO Midstream”). As of June 30, 2007, we operate through TE Products, TCTM and TEPPCO Midstream. Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the “Operating Companies.” Texas Eastern Products Pipeline Company, LLC (the “General Partner”), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. We hold a 99.999% limited partner interest in TCTM and 99.999% membership interests in each of TE Products and TEPPCO Midstream. TEPPCO GP, Inc. (“TEPPCO GP”) holds a 0.001% general partner interest in TCTM and a 0.001% managing member interest in each of TE Products and TEPPCO Midstream.

Through February 23, 2005, the General Partner was an indirect wholly owned subsidiary of DCP Midstream Partners, L.P. (formerly Duke Energy Field Services, LLC) (“DCP”), a joint venture between Duke Energy Corporation (“Duke Energy”) and ConocoPhillips. Duke Energy held an interest of approximately 70% in DCP, and ConocoPhillips held the remaining interest of approximately 30%. On February 24, 2005, the General Partner was acquired by DFI GP Holdings L.P. (“DFIGP”), an affiliate of EPCO, Inc. (“EPCO”), a privately held company controlled by Dan L. Duncan, for approximately $1.1 billion. Additionally, through February 23, 2005, Duke Energy owned 2,500,000 of our Units that have not been listed for trading on the NYSE. On February 24, 2005, DFIGP entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Units for $104.0 million. As of December 31, 2007, none of these Units had been sold by DFIGP. As a result of the sale of our General Partner, DCP and Duke Energy continued to provide some administrative services for us for a period of up to one year after the sale, at which time, we or EPCO assumed these services. Prior to the sale of our General Partner, DCP also managed and operated certain of our TEPPCO Midstream assets for us under contractual agreements. We assumed the operations of these assets from DCP, and certain DCP employees became employees of EPCO effective June 1, 2005.

On May 7, 2007, DFIGP sold all of the membership interests in our General Partner, together with 4,400,000 of our Units, to Enterprise GP Holdings L.P. (“Enterprise GP Holdings”), a publicly traded partnership, also controlled indirectly by Dan L. Duncan. Mr. Duncan and certain of his affiliates, including Enterprise GP Holdings and Dan Duncan LLC, a privately held company controlled by him, control us, our General Partner and Enterprise Products Partners L.P. (“Enterprise Products Partners”) and its affiliates, including Duncan Energy Partners L.P. (“Duncan Energy Partners”). As of May 7, 2007, Enterprise GP Holdings owns and controls the 2% general partner interest in us and has the right (through its 100% ownership of our General Partner) to receive the incentive distribution rights associated with the general partner interest. Enterprise GP Holdings, DFIGP and other entities controlled by Mr. Duncan own 16,691,550 of our Units. Under an amended and restated administrative services agreement (“ASA”), EPCO performs management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us.

Partnership Agreement

On December 8, 2006, at a special meeting of our unitholders, the Fourth Amended and Restated Agreement of Limited Partnership (the "New Partnership Agreement"), which amends and restates the Third Amended and Restated Agreement of Limited Partnership in effect prior to the special meeting (the "Previous Partnership Agreement") was approved and became effective. The New Partnership Agreement contains the following amendments to the Previous Partnership Agreement, among others:

- changes to certain provisions that relate to distributions and capital contributions, including the reduction in the General Partner's incentive distribution rights from 50% to 25% ("IDR Reduction Amendment"), elimination of the General Partner's requirement to make capital contributions to us to maintain a 2% capital account, and adjustment of our minimum quarterly distribution and target distribution levels for entity-level taxes;
- changes to various voting percentage requirements, in most cases from 66 2/3% of outstanding Units to a majority of outstanding Units;
- the percentage of holders of outstanding Units necessary to constitute a quorum was reduced from 66 2/3% to a majority of the outstanding Units;
- removal of provisions requiring unitholder approval for specified actions with respect to the Operating Companies;
- changes to supplement and revise certain provisions that relate to conflicts of interest and fiduciary duties; and
- changes to provide for certain registration rights of the General Partner and its affiliates (including with respect to the Units issued in respect of the IDR Reduction Amendment, as described below), for the maintenance of the separateness of us from any other person or entity and other miscellaneous matters.

References in this Report to our "Partnership Agreement" are to our partnership agreement (including, as applicable, the Previous Partnership Agreement or the New Partnership Agreement), as in effect from time to time. By approval of the various proposals at the special meeting, and upon effectiveness of the New Partnership Agreement, an agreement was effectuated whereby we issued 14,091,275 Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment. Effective as of December 8, 2006, the General Partner distributed the newly issued Units to its member, which in turn caused them to be distributed to other affiliates of EPCO.

On December 27, 2007, our Partnership Agreement was amended in order to comply with the NYSE's eligibility rules regarding the Depository Trust Company's Direct Registration System.

At December 31, 2007, 2006 and 2005, we had outstanding 89,911,532, 89,804,829 and 69,963,554 Units, respectively.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Business Segments

We operate and report in three business segments: transportation, marketing and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies (see Note 14).

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

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. Our procedure for recording an allowance for doubtful accounts is based on (i) our historical experience, (ii) the financial stability of our customers and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. We routinely review our estimates in this area to ensure that we have recorded sufficient reserves to cover potential losses. The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Balance at January 1	$ 100	$ 250	$ 112
Charges to expense	25	64	829
Deductions and other	—	(214)	(691)
Balance at December 31	$ 125	$ 100	$ 250

Asset Retirement Obligations

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

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

We have determined that we are obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of our assets. However, we are not able to reasonably determine the fair value of the AROs for our trunk, interstate and gathering pipelines and our surface facilities, since future dismantlement and removal dates are indeterminate. During 2006, we recorded $0.6 million of expense, included in depreciation and amortization expense, related to conditional AROs related to the retirement of the Val Verde Gas Gathering Company, L.P. (“Val Verde”) natural gas gathering system and to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination. Additionally, we recorded a $1.2 million liability, which represents the fair values of these conditional AROs. During 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded conditional AROs.

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

Basis of Presentation and Principles of Consolidation

The financial statements include our accounts on a consolidated basis. We have eliminated all significant intercompany items in consolidation. We have reclassified certain amounts from prior periods to conform to the current presentation. Our results for the years ended December 31, 2006 and 2005 reflect the operations and activities of Jonah Gas Gathering Company’s (“Jonah”) Pioneer plant as discontinued operations.

Cash and Cash Equivalents

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

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

Capitalization of Interest

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rates used to capitalize interest on borrowed funds were 6.45%, 6.27% and 5.73% for the years ended December 31, 2007, 2006 and 2005, respectively.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Consolidation Policy

We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the entity's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the entity's operating and financial policies. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts are material and remain on our balance sheet (or those of our equity method investments) in inventory or similar accounts. Our investment in Jonah is accounted for under the equity method of accounting, as we do not control Jonah, even though we own an approximate 80% interest in the partnership.

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

Contingencies

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

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

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

Current Assets and Current Liabilities

We present, as individual captions in our consolidated balance sheets, all components of current assets and current liabilities that exceed five percent of total current assets and liabilities, respectively.

Dollar Amounts

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

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Environmental Expenditures

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

The following table presents the activity of our environmental reserve for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Balance at January 1	$ 1,802	$ 2,447	$ 5,037
Charges to expense	3,402	1,887	2,530
Deductions and other	(1,202)	(2,532)	(5,120)
Balance at December 31	$ 4,002	$ 1,802	$ 2,447

Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principals ("GAAP") requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Fair Value of Current Assets and Current Liabilities

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

Financial Instruments

We account for derivative financial instruments in accordance with 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.

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

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

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

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

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

Goodwill

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

If the fair value of the reporting unit exceeds its book value, the goodwill amount is not considered to be impaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value, a charge to earnings is recorded to adjust the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented (see Note 11 for a further discussion of our goodwill).

Income Taxes

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

Revised Texas Franchise Tax

In May 2006, the State of Texas enacted a new business tax (the "Revised Texas Franchise Tax") that replaced its existing franchise tax. In general, legal entities that do business in Texas are subject to the Revised Texas Franchise Tax. Limited partnerships, limited liability companies, corporations, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the Revised Texas Franchise Tax. As a result of the change in tax law, our tax status in the state of Texas changed from nontaxable to taxable. The Revised Texas Franchise Tax is considered an income tax for purposes of adjustments to deferred tax liability, as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. Our deferred income tax expense for state taxes relates only to Revised Texas Franchise Tax obligations. The Revised Texas Franchise Tax becomes effective for franchise tax reports due on or after January 1, 2008. The Revised Texas Franchise Tax due in 2008 will be based on revenues earned during the 2007 fiscal year, excluding the revenue of TE Products Pipeline Company, Limited Partnership and TEPPCO Midstream Companies, L.P. generated prior to June 30, 2007. On June 30, 2007, each of these partnerships converted into a Texas limited partnership and immediately thereafter each merged into a separate newly-formed Texas limited liability company. The pre-June 30, 2007 revenue of each of these partnerships will not be subject to the Revised Texas Franchise Tax because partnerships that did not do business in Texas after June 30, 2007 are not subject to the Revised Texas Franchise Tax pursuant to the Texas transition rules.

The Revised Texas Franchise Tax is assessed at 1% of Texas-sourced taxable margin measured by the ratio of gross receipts from business done in Texas to gross receipts from business done everywhere. The taxable margin is computed as the lesser of (i) 70% of total revenue or (ii) total revenues less (a) cost of goods sold or (b) compensation. The Revised Texas Franchise Tax is calculated, paid and filed at an affiliated unitary group level. Generally, an affiliated group is made up of one or more entities in which a controlling interest of more than 50% is owned by a common owner or owners. Generally, a business is unitary if it is characterized by a sharing or exchange of value between members of the group, and a synergy and mutual benefit all of the members of the group achieved by working together.

Since the Revised Texas Franchise Tax is determined by applying a tax rate to a base that considers both revenues and expenses, it has characteristics of an income tax. Accordingly, we determined the Revised Texas

Franchise Tax should be accounted for as an income tax in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes*.

For the years ended December 31, 2007 and 2006, our provision for income taxes is applicable to our state tax obligations under the Revised Texas Franchise Tax enacted in May 2006. At December 31, 2007, we had a $1.2 million current tax liability and a less than $0.1 million deferred tax asset, while at December 31, 2006, we had a $0.7 million deferred tax liability. During the year ended December 31, 2007, we recorded a reduction to deferred income tax expense of $0.7 million, and an increase in current income tax expense of $1.2 million. During the year ended December 31, 2006, we recorded deferred income tax expense of approximately $0.7 million. The current and deferred income taxes are shown on our statements of consolidated income as provision for income taxes.

Accounting for Uncertainty in Income Taxes

In accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon ultimate settlement with a taxing authority with full knowledge of all relevant information. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows.

Intangible Assets and Excess Investments

Intangible assets on the consolidated balance sheets consist primarily of gathering contracts assumed in the acquisition of Val Verde on June 30, 2002, a fractionation agreement and other intangible assets (see Note 11). Included in equity investments on the consolidated balance sheets are excess investments in Centennial Pipeline LLC ("Centennial"), Seaway Crude Pipeline Company ("Seaway") and Jonah.

In connection with the acquisition of Val Verde, we assumed fixed-term contracts with customers that gather coal bed methane from the San Juan Basin in New Mexico and Colorado. The value assigned to these intangible assets relates to contracts with customers that are for a fixed term. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 11).

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

In connection with the formation of Centennial, we recorded excess investment, the majority of which is amortized on a unit-of-production basis over a period of 10 years. In connection with the acquisition of our interest in Seaway, we recorded excess investment, which is amortized on a straight-line basis over a period of 39 years. In connection with the formation of our Jonah joint venture and the construction of its expansion, we recorded excess investment, which is amortized on a straight-line basis over the life of the assets constructed (see Note 11).

Inventories

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

Natural Gas Imbalances

Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas gathering volumes to our gathering systems than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. To the extent that these shipper imbalances are not cashed out, Val Verde records a payable to shippers who supply more natural gas gathering volumes than nominated, and a receivable from the shippers who nominate more natural gas gathering volumes than supplied. To the extent pipeline imbalances are not cashed out, Val Verde records a receivable from connecting pipeline transporters when total volumes delivered exceed the total of shipper's nominations and records a payable to connecting pipeline transporters when the total shippers' nominations exceed volumes delivered. We record natural gas imbalances using average market prices, which is representative of the estimated value of the imbalances upon final settlement.

Net Income Per Unit

Basic net income per Unit is computed by dividing net income or loss, after deduction of the General Partner's interest, by the weighted average number of distribution-bearing Units outstanding during a period. The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each period (see Note 13). Diluted net income per Unit is computed by dividing net income or loss, after deduction of the General Partner's interest, by the sum of (i) the weighted average number of distribution-bearing Units outstanding during a period (as used in determining basic earnings per Unit); and (ii) the number of incremental Units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units") (see Note 16).

In a period of net operating losses, restricted units and incremental option units are excluded from the calculation of diluted earnings per Unit due to their anti-dilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase Units at an average market value during the period. The amount of Units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase above specified levels, in accordance with our Partnership Agreement. On December 8, 2006, our Partnership Agreement was amended and restated, and our General Partner's maximum percentage interest in our quarterly distributions was reduced from 50% to 25% in exchange for 14.1 million Units (see Note 1).

Property, Plant and Equipment

Property, plant and equipment is recorded at its acquisition cost. Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance expense. Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum).

We evaluate impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated 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 estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell.

Revenue Recognition

Our Downstream Segment revenues are earned from transportation, marketing and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Terminaling revenues are recognized as products are out-loaded. Revenues from the sale of product inventory are recognized when the products are sold. Our refined products marketing activities generate revenues by purchasing refined products from our throughput partners and establishing a margin by selling refined products for physical delivery through spot sales at the Aberdeen truck rack to independent wholesalers and retailers of refined products. These purchases and sales are generally contracted to occur on the same day.

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

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

On April 1, 2006, we adopted Emerging Issues Task Force (“EITF”) 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, which resulted in crude oil inventory purchases and sales under buy/sell transactions, which were previously recorded as gross purchases and sales, to be treated as inventory exchanges in our statements of consolidated income. EITF 04-13 reduced gross revenues and purchases, but did not have a material effect on our financial position, results of operations or cash flows. Under the consensus reached in EITF 04-13, buy/sell transactions are reported as non-monetary exchanges and consequently not presented on a gross basis in our statements of consolidated income. Implementation of EITF 04-13 reduced revenues and purchases of petroleum products on our statements of consolidated income by approximately $2,743.6 million for the year ended December 31, 2007, and $1,127.6 million for the period from April 1, 2006 through December 31, 2006. The revenues and purchases of petroleum products associated with buy/sell transactions that are reported on a gross basis in our statements of consolidated income in the period from January 1, 2006 through March 31, 2006 and for the year ended December 31, 2005, are approximately $275.4 million and $1,405.7 million, respectively. Under the provisions of the consensus, retroactive restatement of buy/sell transactions reported in prior periods was not permitted.

Our Midstream Segment revenues are earned from the gathering of natural gas, transportation of NGLs and fractionation of NGLs. Gathering revenues are recognized as natural gas is received from the customer. Transportation revenues are recognized as NGLs are delivered. Fractionation revenues are recognized ratably over the contract year as products are delivered. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances discussed in “Natural Gas Imbalances.” Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Unit-Based Awards

We account for unit-based awards in accordance with SFAS No. 123(R), *Share-Based Payment*. SFAS 123(R) requires us to recognize compensation expense related to unit-based awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying Units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of a unit-based award is amortized to earnings on a straight-line basis over the requisite service or vesting period of the unit-based awards. As used in the context of the compensation plans, the term “restricted unit” represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires. Compensation for liability awards is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability awards will be settled in cash upon vesting. We accrue compensation expense based upon the terms of each plan (see Note 4).

NOTE 3. RECENT ACCOUNTING DEVELOPMENTS

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Certain requirements of SFAS 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS 157 has been deferred for one year. We adopted the provisions of SFAS 157 which are effective for fiscal years beginning after November 15, 2007, and there was no impact on our financial statements. We are currently evaluating the impact that the deferred provisions of SFAS 157 will have on the disclosures in our financial statements in 2009.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115*. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes the company elects for similar types of assets and liabilities. As a calendar year-end entity, we adopted SFAS 159 on January 1, 2008. Our adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows since we did not elect to fair value any of our eligible financial assets or liabilities.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51*. SFAS 160 establishes accounting and reporting standards for non-controlling interests, which have been referred to as minority interests in prior accounting literature. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent company. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e. elimination of the mezzanine “minority interest” category); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income be allocated between the parent and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests. As a calendar year-end entity, we will adopt SFAS 160 on January 1, 2009, but we do not expect this statement to have a material effect on our financial statements as we do not have any noncontrolling interests.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations.* SFAS 141(R) replaces SFAS No. 141, *Business Combinations*. SFAS 141(R) retains the fundamental requirements of SFAS 141 that the acquisition method of accounting (previously termed the "purchase method") be used for all business combinations and for an acquirer to be identified for each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

- recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.
- recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in earnings as a gain attributable to the acquirer.
- determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder's fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price. As a calendar year-end entity, we will adopt SFAS 141(R) on January 1, 2009. Although we are still evaluating this new guidance, we expect that it will have an impact on the way in which companies evaluate acquisitions. For example, we have made acquisitions in the past where the fair value of assets acquired and liabilities assumed was in excess of the purchase price. In those cases, a bargain purchase would have been recognized under SFAS 141(R).

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NOTE 4. ACCOUNTING FOR UNIT-BASED AWARDS

The following table summarizes compensation expense by plan for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Phantom Unit Plans (1):			
1994 Long-Term Incentive Plan (“1994 LTIP”) (2)	$ —	$ 4	$ 7
1999 Phantom Unit Retention Plan	865	885	4
2000 Long Term Incentive Plan	397	352	1,486
2002 Phantom Unit Retention Plan (3)	—	—	873
2005 Phantom Unit Plan	976	1,152	714
EPCO, Inc. 2006 TPP Long-Term Incentive Plan:			
Unit options	65	—	—
Restricted units (4)	338	—	—
Unit appreciation rights (“UARs”) (1)	67	—	—
Phantom units (1)	12	—	—
Compensation expense allocated under ASA (5)	1,062	201	7
Total compensation expense	$ 3,782	$ 2,594	$ 3,091

(1) These awards are accounted for as liability awards under the provisions of SFAS 123(R). Accruals for plan award payouts are based on the Unit price (see discussion of plans below).

(2) The 1994 LTIP provided certain key employees with an incentive award whereby the participant was granted an option to purchase Units and performance units. The 1994 LTIP was terminated effective as of June 19, 2006.

(3) The terms of the 2002 Phantom Unit Retention Plan were similar to the 1999 Plan (discussed below), and the plan fully vested and paid out in 2005.

(4) As used in the context of the 2006 LITP, the term “restricted unit” represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

(5) Represents compensation expense under equity awards allocated to us from EPCO under the ASA in connection with shared service employees working on TEPPCO.

1999 Plan

The Texas Eastern Products Pipeline Company, LLC 1999 Phantom Unit Retention Plan (“1999 Plan”) provides for the issuance of phantom unit awards as incentives to key employees. These liability awards are settled for cash based on the fair market value of the vested portion of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the closing price of a Unit on the NYSE on the redemption date. Each participant is required to redeem their phantom units as they vest. Each participant is also entitled to cash distributions equal to the product of the number of phantom units granted to the participant and the per Unit cash distribution that we paid to our unitholders. Grants under the 1999 Plan are subject to forfeiture if the participant’s employment with EPCO is terminated.

A total of 31,600 phantom units were outstanding under the 1999 Plan at December 31, 2007. These awards cliff vest as follows: 13,000 in April 2008; 13,000 in April 2009; and 5,600 in January 2010. At December 31, 2007 and 2006, we had accrued liability balances of $1.0 million and $0.8 million, respectively, for compensation related to the 1999 Plan.

2000 LTIP

The Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") provides key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, the participant will receive a cash payment equal to (i) the applicable "performance percentage" as specified in the award multiplied by (ii) the number of phantom units granted under the award multiplied by (iii) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. In addition, during the performance period, each participant is entitled to cash distributions equal to the product of the number of phantom units granted to the participant and the per Unit cash distribution that we paid to our unitholders. Grants under the 2000 LTIP are accounted for as liability awards and subject to forfeiture if the participant's employment with EPCO is terminated, with customary exceptions for death, disability or retirement.

A participant's "performance percentage" is based upon an improvement in Economic Value Added during a given three-year performance period over the Economic Value Added for the three-year period immediately preceding the performance period. The term "Economic Value Added" means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. In this context, EBITDA means earnings before net interest expense, other income — net, depreciation and amortization and our proportional interest in the EBITDA of our joint ventures, except that our chief executive officer may exclude gains or losses from extraordinary, unusual or non-recurring items. Average asset base means the quarterly average, during the performance period, of our gross carrying value of property, plant and equipment, plus long-term inventory, and the gross carrying value of intangibles and equity investments. The cost of capital is determined at the date each award is granted.

There were a total of 19,700 phantom units outstanding under the 2000 LTIP at December 31, 2007 that cliff vest as follows: 8,400 vested on December 31, 2007 and will be paid out to participants in 2008, and 11,300 will vest on December 31, 2008 and will be paid out to participants in 2009. At December 31, 2007 and 2006, we had accrued liability balances of $0.9 million and $0.6 million, respectively, related to the 2000 LTIP.

2005 Phantom Unit Plan

The Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 Phantom Unit Plan") provides key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, the participant will receive a cash payment equal to (i) the applicable "performance percentage" as specified in the award multiplied by (ii) the number of phantom units granted under the award multiplied by (iii) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. In addition, during the performance period, each participant is entitled to cash distributions equal to the product of the number of phantom units granted to the participant and the per Unit cash distribution that we paid to our unitholders. Grants under the 2005 Phantom Unit Plan are accounted for as liability awards and subject to forfeiture if the participant's employment with EPCO is terminated, with customary exceptions for death, disability or retirement.

Generally, a participant's performance percentage is based upon the achievement of a cumulative EBITDA for the performance period of an amount equal to the sum of the EBITDA targets established for each of the three years of the performance period. In this context, EBITDA means earnings before net interest expense, other income — net, depreciation and amortization and our proportional interest in the EBITDA of our joint ventures, except that our chief executive officer may exclude gains or losses from extraordinary, unusual or non-recurring items.

There were a total of 74,400 phantom units were outstanding under the 2005 Phantom Unit Plan at December 31, 2007 that cliff vest as follows: 36,200 vested on December 31, 2007 and will be paid out to participants in 2008, and 38,200 will vest on December 31, 2008 and will be paid out to participants in 2009. At December 31, 2007 and 2006, we had accrued liability balances of $2.6 million and $1.6 million, respectively, for compensation related to the 2005 Phantom Unit Plan.

2006 LTIP

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP"), which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards granted under the 2006 LTIP may be in the form of restricted units, phantom units, unit options, UARs and distribution equivalent rights. The exercise price of unit options or UARs awarded to participants is determined by the Audit, Conflicts and Governance Committee of the board of directors of our General Partner ("ACG Committee") (at its discretion) at the date of grant and may be no less than the fair market value of the option award as of the date of grant. The 2006 LTIP is administered by the ACG Committee. Subject to adjustment as provided in the 2006 LTIP, awards with respect to up to an aggregate of 5,000,000 Units may be granted under the 2006 LTIP. We reimburse EPCO for the costs allocable to 2006 LTIP awards made to employees who work in our business.

On April 30, 2007 and May 2, 2007, the non-employee directors of our General Partner were awarded 1,647 phantom units, which payout in 2011, and 66,225 UARs, which vest in 2012. On May 22, 2007, 155,000 unit options, 62,900 restricted units and 338,479 UARs were granted to employees providing services directly to us, which vest in 2011, 2011 and 2012, respectively.

The 2006 LTIP may be amended or terminated at any time by the board of directors of EPCO, which is an affiliate of our General Partner, or the ACG Committee; however, any material amendment, such as a material increase in the number of Units available under the plan or a change in the types of awards available under the plan, would require the approval of at least 50% of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2006 LTIP in specified circumstances. The 2006 LTIP is effective until December 8, 2016 or, if earlier, the time which all available Units under the 2006 LTIP have been delivered to participants or the time of termination of the 2006 LTIP by EPCO or the ACG Committee. After giving effect to outstanding unit options and restricted units at December 31, 2007, and the forfeiture of restricted units (see below) through December 31, 2007, a total of 4,782,600 additional Units could be issued under the 2006 LTIP in the future.

Unit Options

The information in the following table presents unit option activity under the 2006 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/Unit)	Weighted-Average Remaining Contractual Term (in years)
Unit Options:			
Outstanding at December 31, 2006	—	$ —	—
Granted in May 2007 (1)	155,000	45.35	—
Outstanding at December 31, 2007	155,000	$ 45.35	9.39
Options exercisable at:			
December 31, 2007	—	$ —	—

(1) The total grant date fair value of these awards was $0.4 million based on the following assumptions: (i) expected life of option of 7 years, (ii) risk-free interest rate of 4.78%; (iii) expected distribution yield on Units of 7.92%; and (iv) expected Unit price volatility on Units of 18.03%.

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At December 31, 2007, total unrecognized compensation cost related to restricted unit options granted under the 2006 LTIP was an estimated $0.4 million. We expect to recognize this cost over a weighted-average period of 3.39 years.

Restricted Units

The following table summarizes information regarding our restricted units for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted Units at December 31, 2006	—	
Granted (2)	62,900	$ 37.64
Forfeited	(500)	37.64
Restricted Units at December 31, 2007	62,400	$ 37.64

(1) Determined by dividing the aggregate grant date fair value of awards (including an allowance for forfeitures) by the number of awards issued.

(2) Aggregate grant date fair value of restricted unit awards issued during 2007 was $2.4 million based on a grant date market price of our Units of $45.35 per Unit and an estimated forfeiture rate of 17%.

None of our restricted units vested during the year ended December 31, 2007. At December 31, 2007, total unrecognized compensation cost related to restricted units was $2.0 million, and these costs are expected to be recognized over a weighted-average period of 3.39 years.

Phantom Units and UARs

On April 30, 2007, the non-executive members of the board of directors were each awarded 549 phantom units under the 2006 LTIP. Each phantom unit will pay out in cash on April 30, 2011 or, if earlier, the date the director is no longer serving on the board of directors, whether by voluntarily resignation or otherwise (“Payment Date”). In addition, for each calendar quarter from the grant date until the Payment Date, each non-executive director will receive a cash payment within such calendar quarter equal to the product of (i) the per Unit cash distributions paid to our unitholders during such calendar quarter, if any, multiplied by (ii) the number of phantom units subject to their grant. Phantom unit awards to non-employee directors are accounted for similar to SFAS 123(R) liability awards.

On May 2, 2007, the non-executive members of the board of directors were each awarded 22,075 UARs under the 2006 LTIP at an exercise price of $45.30 per Unit. The UARs will be subject to five year cliff vesting and will vest earlier if the director dies or is removed from, or not re-elected or appointed to, the board of directors for reasons other than his voluntary resignation or unwillingness to serve. When the UARs become payable, the director will receive a payment in cash equal to the fair market value of the Units subject to the UARs on the payment date over the fair market value of the Units subject to the UARs on the date of grant. UARs awarded to non-executive directors are accounted for similar to SFAS 123(R) liability awards.

On May 22, 2007, 338,479 UARs were granted under the 2006 LTIP to certain employees providing services directly to us at an exercise price of $45.35 per Unit. The UARs are subject to five year cliff vesting and are subject to forfeiture. When the UARs become payable, the awards will be redeemed in cash (or, in the sole discretion of the ACG Committee, Units or a combination of cash and Units) equal to the fair market value of the Units subject to the UARs on the payment date over the fair market value of the Units subject to the UARs on the date of grant. In addition, for each calendar quarter from the grant date until the UARs become payable, each holder will receive a cash payment equal to the product of (i) the per Unit cash distribution paid to our unitholders during such calendar quarter less the quarterly distribution amount in effect at the time of grant multiplied by (ii) the number of Units subject to the UAR. UARs awarded to employees are accounted for as liability awards under SFAS 123(R) since the current intent is to settle the awards in cash.

NOTE 5. EMPLOYEE BENEFIT PLANS

Retirement Plans

The TEPPCO Retirement Cash Balance Plan (“TEPPCO RCBP”) was a non-contributory, trustee-administered pension plan. In addition, the TEPPCO Supplemental Benefit Plan (“TEPPCO SBP”) was a non-contributory, nonqualified, defined benefit retirement plan, in which certain executive officers participated. The TEPPCO SBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans. The benefit formula for all eligible employees was a cash balance formula. Under a cash balance formula, a plan participant accumulated a retirement benefit based upon pay credits and current interest credits. The pay credits were based on a participant’s salary, age and service. We used a December 31 measurement date for these plans.

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended. Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date. Effective June 1, 2005, EPCO adopted the TEPPCO RCBP and the TEPPCO SBP for the benefit of its employees providing services to us. Effective December 31, 2005, all plan benefits accrued were frozen, participants received no additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service. The TEPPCO RCBP plan was terminated effective December 31, 2005, and plan participants had the option to receive their benefits either through a lump sum payment or through an annuity. In April 2006, we received a determination letter from the Internal Revenue Service (“IRS”) providing IRS approval of the plan termination. For those plan participants who elected to receive an annuity, we purchased an annuity contract from an insurance company in which the plan participants own the annuity, absolving us of any future obligation to the participants. Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005.

In June 2005, we recorded a curtailment charge of $0.1 million in accordance with SFAS No. 88, *Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments. As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table. The discount rate was decreased from 5.75% to 5.00% to reflect rates of returns on bonds currently available to settle the liability. The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds. The mortality table was changed to reflect overall improvements in mortality experienced by the general population. The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs. We recorded settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP. We recorded settlement charges of approximately $0.1 million and $3.5 million during the years ended December 31, 2007 and 2006, respectively, relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants. As of December 31, 2007, all benefit obligations to plan participants have been settled.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2007, 2006 and 2005, were as follows:

	For Year Ended December 31, 2007	2006	2005
Service cost benefit earned during the year	$ —	$ —	$ 4,393
Interest cost on projected benefit obligation	14	891	934
Expected return on plan assets	103	(412)	(671)
Amortization of prior service cost	—	—	5
Recognized net actuarial loss	38	135	129
SFAS 88 curtailment charge	—	—	50
SFAS 88 settlement charge	87	3,545	194
Net pension benefits costs	$ 242	$ 4,159	$ 5,034

The weighted average discount rate used to determine benefit obligations for the retirement plans at December 31, 2006 was 4.73%. The weighted average assumptions used to determine net periodic benefit cost for the retirement plans for the years ended December 31, 2007 and 2006, were discount rates of 4.73% and 4.59%, respectively, and expected long-term rate of return on plan assets of 2% for both years.

The following table sets forth our pension benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2007 and 2006:

	December 31, 2007	2006
Change in benefit obligation		
Benefit obligation at beginning of year	$ 477	$ 22,111
Interest cost	14	891
Actuarial loss	60	152
Benefits paid	(534)	(22,677)
Impact of settlement	(17)	—
Benefit obligation at end of year	$ —	$ 477
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,311	$ 23,104
Actual return on plan assets	(72)	884
Benefits paid	(534)	(22,677)
Impact of settlement	(46)	—
Fair value of plan assets at end of year	$ 659	$ 1,311
Funded status	$ 659	$ 834
Amount Recognized in the Balance Sheet:		
Noncurrent assets	$ 659	$ 834
Net pension asset at end of year	$ 659	$ 834
Amount Recognized in Accumulated Other Comprehensive Income:		
Unrecognized actuarial loss	$ —	$ 67
Amount Recognized in Other Comprehensive Income:		
Net actuarial loss (gain)	$ 57	$ —
Amortization of net actuarial loss (gain)	(124)	—
Total recognized in other comprehensive income	$ (67)	$ —

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table illustrates the incremental effect of applying SFAS No. 158 on individual line items in the consolidated balance sheet as of December 31, 2006:

	December 31, 2006		
	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Prepaid pension cost (included in other current assets)	$ 901	$(901)	$ —
Other assets	71,827	834	72,661
Total assets	3,922,159	(67)	3,922,092
Accumulated other comprehensive income	493	(67)	426
Total partners' capital	1,320,397	(67)	1,320,330
Total liabilities and partners' capital	3,922,159	(67)	3,922,092

Plan Assets

At December 31, 2007 and 2006, all plan assets for the TEPPCO RCBP were invested in money market securities. No further contributions will be made to the TEPPCO RCBP.

Other Postretirement Benefits

We provided certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees became eligible for these benefits if they met certain age and service requirements at retirement, as defined in the plans. We provided a fixed dollar contribution, which did not increase from year to year, towards retired employee medical costs. The retiree paid all health care cost increases due to medical inflation. We used a December 31 measurement date for this plan.

In May 2005, benefits provided to employees under the TEPPCO OPB were changed. Employees eligible for these benefits received them through December 31, 2005, however, effective December 31, 2005, these benefits were terminated. As a result of this change in benefits and in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, we recorded a curtailment credit of approximately $1.7 million in our accumulated postretirement obligation which reduced our accumulated postretirement obligation to the total of the expected remaining 2005 payments under the TEPPCO OPB. The employees participating in this plan at that time were transferred to DCP, who is expected to provide postretirement benefits to these retirees. We recorded a one-time settlement to DCP in the third quarter of 2005 of $0.4 million for the remaining postretirement benefits.

The components of net postretirement benefits cost for the TEPPCO OPB for the years ended December 31, 2007, 2006 and 2005, were as follows:

	For Year Ended December 31,		
	2007	2006	2005
Service cost benefit earned during the year	$ —	$ —	$ 81
Interest cost on accumulated postretirement benefit obligation	—	—	69
Amortization of prior service cost	—	—	53
Recognized net actuarial loss	—	—	4
Curtailment credit	—	—	(1,676)
Settlement credit	—	—	(4)
Net postretirement benefits costs	$ —	$ —	$ (1,473)

Effective June 1, 2005, the payroll functions performed by DCP for our General Partner were transferred from DCP to EPCO. For those employees who were receiving certain other postretirement benefits at the time of

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the acquisition of our General Partner by DFIGP, DCP is expected to continue to provide these benefits to those employees. Effective June 1, 2005, EPCO began providing certain other postretirement benefits to those employees who became eligible for the benefits after June 1, 2005, and will charge those benefit related costs to us (see Note 15). As a result of these changes, we recorded a $1.2 million reduction in our other postretirement obligation in June 2005.

Other Plans

DCP also sponsored an employee savings plan, which covered substantially all employees. Effective February 24, 2005, in conjunction with the change in ownership of our General Partner, our participation in this plan ended. Plan contributions on behalf of the General Partner of $0.9 million were recognized for the period January 1, 2005 through February 23, 2005.

EPCO maintains a 401(k) plan for the benefit of employees providing services to us and effective January 1, 2008, will maintain a retirement plan for the benefit of employees providing services to us, and we will continue to reimburse EPCO for the cost of maintaining these plans in accordance with the ASA.

NOTE 6. FINANCIAL INSTRUMENTS

The following table presents the estimated fair values of our financial instruments at December 31, 2007 and 2006:

	December 31,			
	2007		2006	
Financial Instruments	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents (1)	$ 23	$ 23	$ 70	$ 70
Accounts receivable (1)	1,381,871	1,381,871	852,816	852,816
Commodity financial instruments (2) (3)	10,458	10,458	741	741
Interest rate swaps (3) (4)	254	254	1,393	1,393
Treasury rate locks (3) (4)	—	—	64	64
Financial liabilities:				
Accounts payable and accrued expenses (1)	1,413,447	1,413,447	855,306	855,306
Fixed-rate debt (principal amount) (5)	1,355,000	1,370,830	1,090,000	1,141,789
Variable-rate debt (6)	490,000	490,000	490,000	490,000
Commodity financial instruments (2) (3)	29,355	29,355	—	—
Interest rate swaps (3) (4)	—	—	2,629	2,629
Treasury rate locks (3) (4)	25,296	25,296	56	56

(1) Cash and cash equivalents, accounts receivable and accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values due to their short-term nature.

(2) Represents commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

(3) The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(4) Represents interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

(5) The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities (see Note 12).

(6) The carrying amount of our variable rate debt obligation reasonably approximates its fair value due to its variable interest rate.

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

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

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates, resulting in the realization of income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Interest Rate Swaps

We utilize interest rate swap agreements to manage our cost of borrowing. The following table summarizes our interest rate swaps outstanding at December 31, 2007.

Hedged Debt	Number of Swaps	Period Covered by Swaps	Termination Date of Swaps	Rate Swaps	Notional Value
Revolving Credit Facility, due Dec. 2012	4	Jan. 2006 to Jan. 2008	Jan. 2008	Swapped 5.18% floating rate for fixed rates ranging from 4.67% to 4.695% (1)	$200.0 million

(1) On June 30, 2007, these interest rate swap agreements were de-designated as cash flow hedges and are now accounted for using mark-to-market accounting; thus, changes in the fair value of these swaps are recognized in earnings. At December 31, 2007 and 2006, the fair values of these interest rate swaps were assets of $0.3 million and $1.4 million, respectively.

Interest Rate Swap Terminations. In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7.51% Senior Notes due 2028. This swap agreement, designated as a fair value hedge, had a notional amount of $210.0 million and was set to mature in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products paid a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread of 147 basis points, and received a fixed rate of interest of 7.51%. During the years ended December 31, 2007, 2006 and 2005, we recognized reductions in interest expense of $0.3 million, $1.9 million and $5.6 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. The fair value of this interest rate swap was a liability of approximately $2.6 million at December 31, 2006. In September 2007, we terminated this interest rate swap agreement resulting in a loss of $1.2 million. This loss was deferred as an adjustment to the carrying value of the 7.51% Senior Notes, and approximately $0.2 million of the loss was amortized to interest expense in 2007, with the remaining balance recognized as interest expense in January 2008 at the time the 7.51% Senior Notes were redeemed.

During 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7.625% Senior Notes due 2012. The swap agreements had a combined notional amount of $500.0 million and were set to mature in 2012 to match the principal and maturity of the underlying debt. These swap agreements were terminated in 2002 resulting in deferred gains of $44.9 million, which are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the 7.625% Senior Notes. At December 31, 2007 and 2006, the unamortized balance of the deferred gains was $23.2 million and $28.0 million, respectively. In the event of early extinguishment of the 7.625% Senior Notes, any remaining unamortized gains would be recognized in the statement of consolidated income at the time of extinguishment.

Treasury Locks

In October 2006 and February 2007, we entered into treasury lock agreements, accounted for as cash flow hedges, that extended through June 2007 for a notional amount totaling $300.0 million. In May 2007, these treasury locks were terminated concurrent with the issuance of junior subordinated notes (see Note 12). The termination of the treasury locks resulted in gains of $1.4 million, and these gains were recorded in other comprehensive income. These gains are being amortized using the effective interest method as reductions to future interest expense over the fixed rate term of the junior subordinated notes, which is ten years. In the event of early extinguishment of the junior subordinated notes, any remaining unamortized gains would be recognized in the statement of consolidated income at the time of extinguishment.

In 2007, we entered into treasury lock agreements that extend through January 31, 2008 for a notional amount totaling $600.0 million. These instruments have been designated as cash flow hedges to offset our exposure to increases in the underlying U.S. Treasury benchmark rates that are expected to be used to establish the fixed interest rate for debt that we expect to incur in 2008. The weighted average rate under the treasury locks was approximately 4.39%. The actual coupon rate of the expected debt will be comprised of the underlying U.S. Treasury benchmark rate, plus a credit spread premium at the date of issuance. At December 31, 2007, the fair value of the treasury locks was a liability of $25.3 million. To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is issued and will be amortized to earnings over the life of the debt. No ineffectiveness was recognized as of December 31, 2007.

During May 2005, we executed a treasury lock agreement for a notional amount of $200.0 million to hedge our exposure to increases in the treasury rate that was to be used to establish the fixed interest rate for a debt offering that was proposed to occur in the second quarter of 2005. During June 2005, the proposed debt offering was cancelled, and the treasury lock was terminated with a realized loss of $2.0 million. The realized loss was recorded as a component of interest expense in the statements of consolidated income in June 2005.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Commodity Risk Hedging Program

We seek to maintain a position that is substantially balanced between crude oil purchases and related sales and future delivery obligations. As part of our crude oil marketing business, we enter into financial instruments such as swaps and other hedging instruments. The purpose of such hedging activity is to either balance our inventory position or to lock in a profit margin.

At December 31, 2007 and 2006, we had a limited number of commodity derivatives that were accounted for as cash flow hedges. These contracts will expire during 2008, and any amounts remaining in accumulated other comprehensive income will be recorded in net income. Gains and losses on these derivates are offset against corresponding gains or losses of the hedged item and are deferred through other comprehensive income, thus minimizing exposure to cash flow risk. In addition, we had some commodity derivatives that did not qualify for hedge accounting. These financial instruments had a minimal impact on our earnings. The fair value of these open positions at December 31, 2007 and 2006 was a liability of $18.9 million and an asset of $0.7 million, respectively. No ineffectiveness was recognized as of December 31, 2007.

NOTE 7. INVENTORIES

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at December 31, 2007 and 2006. The major components of inventories were as follows:

	December 31,	
	2007	2006
Crude oil (1)	$ 44,542	$ 49,312
Refined products and LPGs (2)	18,616	7,636
Lubrication oils and specialty chemicals	9,160	7,500
Materials and supplies	7,178	7,029
NGLs	803	716
Total	$ 80,299	$ 72,193

(1) At December 31, 2007 and 2006, $16.5 million and $44.0 million, respectively, of our crude oil inventory was subject to forward sales contracts.

(2) Refined products and LPGs inventory is managed on a combined basis.

Due to fluctuating commodity prices in the crude oil, refined products and LPG industries, we recognize lower of cost or market (“LCM”) adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of costs and expenses in the period they are recognized. For the years ended December 31, 2007, 2006 and 2005, we recognized LCM adjustments of approximately $0.8 million, $1.7 million and $7 thousand, respectively.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment at December 31, 2007 and 2006, were as follows:

	Estimated Useful Life In Years	December 31, 2007	December 31, 2006
Plants and pipelines (1)	5-40(4)	$ 1,810,195	$ 1,615,867
Underground and other storage facilities (2)	5-40(5)	254,677	196,306
Transportation equipment (3)	5-10	7,780	8,200
Land and right of way		117,628	128,791
Construction work in progress		185,579	202,820
Total property, plant and equipment		2,375,859	$ 2,151,984
Less accumulated depreciation		582,225	509,889
Property, plant and equipment, net		$ 1,793,634	$ 1,642,095

(1) Plants and pipelines include refined products, LPGs, NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings, laboratory and shop equipment; and related assets.

(2) Underground and other storage facilities include underground product storage caverns, storage tanks and other related assets.

(3) Transportation equipment includes vehicles and similar assets used in our operations.

(4) The estimated useful lives of major components of this category are as follows: pipelines, 20-40 years (with some equipment at 5 years); terminal facilities, 10-40 years; office furniture and equipment, 5-10 years; buildings 20-40 years; and laboratory and shop equipment, 5-40 years.

(5) The estimated useful lives of major components of this category are as follows: underground storage facilities, 20-40 years (with some components at 5 years) and storage tanks, 20-30 years.

The following table summarizes our depreciation expense and capitalized interest amounts for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31, 2007	2006	2005
Depreciation expense (1)	$81,093	$78,888	$80,205
Capitalized interest (2)	11,030	10,681	6,759

(1) Depreciation expense is a component of depreciation and amortization expense as presented in our statements of consolidated income.

(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

In September 2005, our Todhunter facility, near Middletown, Ohio, experienced a propane release and fire at a dehydration unit within the storage facility. The facility is included in our Downstream Segment. The dehydration unit was destroyed due to the propane release and fire, and as a result, we wrote off the remaining book value of the asset of $0.8 million to depreciation and amortization expense during the third quarter of 2005.

During the third quarter of 2005, our Upstream Segment was notified by a connecting carrier that the flow of its pipeline system would be reversed, which would directly impact the viability of one of our pipeline systems.

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This system, located in East Texas, consists of approximately 45 miles of pipeline, six tanks of various sizes and other equipment and asset costs. As a result of changes to the connecting carrier, we performed an impairment test of the system and recorded a $1.8 million non-cash impairment charge, included in depreciation and amortization expense in our statements of consolidated income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2005, we completed an evaluation of a crude oil system included in our Upstream Segment. The system, located in Oklahoma, consists of approximately six miles of pipelines, tanks and other equipment and asset costs. The usage of the system has declined in recent months as a result of shifting crude oil production into areas not supported by the system, and as such, it has become more economical to transport barrels by truck to our other pipeline systems. As a result, we performed an impairment test on the system and recorded a $0.8 million non-cash impairment charge, included in depreciation and amortization expense in our statements of consolidated income, for the excess carrying value over the estimated fair value of the system.

Asset Retirement Obligations

During 2006, we recorded $0.6 million of expense, included in depreciation and amortization expense, related to conditional AROs related to the retirement of the Val Verde natural gas gathering system and to structural restoration work to be completed on leased office space that is required upon our anticipated office lease termination. Additionally, we have recorded a $1.2 million liability, which represents the fair values of these conditional AROs. During 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded conditional AROs.

The following table presents information regarding our AROs:

ARO liability balance, December 31, 2005	$ —
Liabilities incurred	1,189
Accretion expense	39
ARO liability balance, December 31, 2006	1,228
Liabilities incurred	—
Accretion expense	118
ARO liability balance, December 31, 2007	$ 1,346

Property, plant and equipment at December 31, 2007, includes $0.5 million of asset retirement costs capitalized as an increase in the associated long-lived asset. Additionally, based on information currently available, we estimate that accretion expense will approximate $0.1 million for 2008, $0.1 million for 2009, $0.2 million for 2010, $0.2 million for 2011 and $0.2 million for 2012.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 9. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We own interests in related businesses that are accounted for using the equity method of accounting. These investments are identified below by reporting business segment (see Note 14 for a general discussion of our business segments). The following table presents our investments in unconsolidated affiliates as of December 31, 2007 and 2006:

	Ownership Percentage at December 31, 2007	Investments in unconsolidated affiliates at December 31, 2007	2006
Downstream Segment:			
Centennial	50.0%	$ 78,962	$ 62,321
MB Storage (1)	—	—	85,626
Other	25.0%	362	369
Upstream Segment:			
Seaway	50.0%	188,650	195,584
Midstream Segment:			
Jonah	80.64%	879,021	695,810
Total		$ 1,146,995	$ 1,039,710

(1) Refers to our ownership interests in Mont Belvieu Storage Partners, L.P. and Mont Belvieu Venture, LLC (collectively, “MB Storage”). On March 1, 2007, we sold our ownership interests in these entities.

The following table summarizes equity earnings (losses) by business segment for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31, 2007	2006	2005
Equity earnings (losses):			
Downstream Segment	$ (12,396)	$ (8,018)	$ (2,984)
Upstream Segment	2,602	11,905	23,078
Midstream Segment	83,060	35,052	—
Intersegment eliminations	(4,511)	(2,178)	—
Total equity earnings	$ 68,755	$ 36,761	$ 20,094

Seaway

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway. The remaining 50% interest is owned by ConocoPhillips. We operate and commercially manage the Seaway assets. Seaway owns pipelines and terminals that carry imported, offshore and domestic onshore crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas and from a connection in the South Texas system that allows Seaway to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through December 31, 2005, we received 60% of revenue and expense of Seaway. The sharing ratio (including the amount of distributions we receive) changed from 60% to 40% on March 12, 2006, and as such, our share of revenue and expense of Seaway was 47% for 2006. Thereafter, we receive 40% of revenue and expense (and distributions) of Seaway. During the years ended December 31, 2007, 2006 and 2005, we received distributions from Seaway of $12.4 million, $20.5 million and $24.7 million, respectively. During the years ended December 31, 2007, 2006 and 2005, we did not invest any funds in Seaway.

Centennial

TE Products owns a 50% ownership interest in Centennial, and Marathon Petroleum Company LLC (“Marathon”) owns the remaining 50% interest. Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Marathon operates the mainline Centennial pipeline, and TE Products operates the Beaumont origination point and the Creal Springs terminal. During the year ended December 31, 2007, TE Products contributed $11.1 million to Centennial, of which $6.1 million was for contractual obligations that were created upon formation of Centennial and $5.0 million was for debt service requirements. During the years ended December 31, 2006 and 2005, TE Products contributed $2.5 million and $0, respectively, to Centennial. TE Products has received no cash distributions from Centennial since its formation.

MB Storage

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L.P. (“Louis Dreyfus”) formed MB Storage. Through February 28, 2007, TE Products owned a 49.5% ownership interest in MB Storage and a 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage), and Louis Dreyfus owned the remaining interests. Pursuant to a Bureau of Competition of the Federal Trade Commission (“FTC”) order and consent agreement (see Note 17), on March 1, 2007, TE Products sold its ownership interests in MB Storage and its general partner to Louis Dreyfus (see Note 10). MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short-haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. TE Products operated the facilities for MB Storage through February 28, 2007.

TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage’s income before depreciation expense, as defined in the Agreement of Limited Partnership of MB Storage. TE Products’ share of MB Storage’s earnings was adjusted annually by the partners of MB Storage. Any amount of MB Storage’s annual income before depreciation expense in excess of $6.78 million was allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage was allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation was allocated evenly between TE Products and Louis Dreyfus. For the period from January 1, 2007 through February 28, 2007 and for the years ended December 31, 2006 and 2005, TE Products’ sharing ratios in the earnings of MB Storage were 67.7%, 59.4% and 64.2%, respectively. During the period from January 1, 2007 through February 28, 2007, TE Products received distributions from MB Storage of $10.4 million and made no contributions to MB Storage. During the years ended December 31, 2006 and 2005, TE Products received distributions of $12.9 million and $12.4 million, respectively, from MB Storage. During the years ended December 31, 2006 and 2005, TE Products contributed $4.8 million and $5.6 million, respectively, to MB Storage. The 2005 contribution includes a combination of non-cash asset transfers of $1.4 million and cash contributions of $4.2 million.

Jonah

On August 1, 2006, Enterprise Products Partners, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah, the partnership through which we have owned our interest in the Jonah system. The joint venture is governed by a management committee comprised of two representatives approved by Enterprise Products Partners and two representatives approved by us, each with equal voting power. The formation of the joint venture was reviewed and recommended for approval by our ACG Committee. Enterprise Products Partners serves as operator of Jonah. Prior to entering into the Jonah joint venture, Enterprise Products Partners had managed the construction of the Phase V expansion and funded the initial costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and

Enterprise Products Partners plan to continue the Phase V expansion, which is expected to increase the system capacity of the Jonah system from 1.5 billion cubic feet ("Bcf") per day to approximately 2.35 Bcf per day and to significantly reduce system operating pressures, which is anticipated to lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which increased the system gathering capacity to approximately 2.0 Bcf per day, was completed in July 2007. The second and final portion of the expansion is expected to be completed during April 2008. Enterprise Products Partners manages the Phase V construction project.

From August 1, 2006 through July 2007, we and Enterprise Products Partners equally shared the costs of the Phase V expansion, and Enterprise Products Partners shared in the incremental cash flow resulting from the operation of those new facilities. During August 2007, with the completion of the first portion of the expansion, we and Enterprise Products Partners began sharing joint venture cash distributions and earnings based on a formula that takes into account the capital contributions of the parties, including expenditures by us prior to the expansion. Based on this formula in the partnership agreement, at December 31, 2007, our ownership interest in Jonah was approximately 80.64%, and Enterprise Products Partners' ownership interest in Jonah was approximately 19.36%. To the extent the costs exceed an agreed upon base cost estimate of $415.2 million, we and Enterprise Products Partners will each pay our respective ownership share (approximately 80% and 20%, respectively). Our ownership interest in Jonah is currently anticipated to remain at 80.64%.

Through December 31, 2007, we have reimbursed Enterprise Products Partners $261.6 million ($152.2 million in 2007 and $109.4 million in 2006) for our share of the Phase V cost incurred by it (including its cost of capital incurred prior to the formation of the joint venture of $1.3 million). At December 31, 2007 and 2006, we had payables to Enterprise Products Partners for costs incurred of $9.9 million and $8.7 million, respectively. During the year ended December 31, 2006, Jonah declared a distribution to us of $41.6 million, of which $30.0 million was paid in cash and the remainder was reflected as a receivable from Jonah. During the year ended December 31, 2007, we received distributions from Jonah of $100.0 million, which included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the years ended December 31, 2007 and 2006, we invested $187.5 million and $121.0 million, respectively, in Jonah.

Summarized Financial Information of Unconsolidated Affiliates

Summarized combined income statement data by reporting segment for the years ended December 31, 2007 and 2006 is presented below (on a 100% basis):

	For Year Ended December 31,					
	2007			2006		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income (Loss)
Downstream Segment (1)	$ 56,816	$13,156	$ 2,365	$73,124	$10,374	$ (538)
Upstream Segment	67,337	21,266	21,589	87,284	34,206	34,608
Midstream Segment (2)	204,146	92,212	93,120	79,618	34,646	34,743

(1) On March 1, 2007, we sold our ownership interest in MB Storage to Louis Dreyfus.

(2) Effective August 1, 2006, with the formation of a joint venture with Enterprise Products Partners, Jonah was deconsolidated and has been subsequently accounted for as an equity investment.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Summarized combined balance sheet information by reporting segment as of December 31, 2007 and 2006, is presented below:

	December 31, 2007					
	Current Assets	Noncurrent Assets	Current Liabilities	Long-term Debt	Noncurrent Liabilities	Partners' Capital
Downstream Segment (1)	$20,864	$ 248,896	$23,814	$129,900	$365	$ 115,681
Upstream Segment	16,429	251,635	6,457	—	38	261,569
Midstream Segment	55,396	1,065,304	22,545	—	264	1,097,891

	December 31, 2006					
	Current Assets	Noncurrent Assets	Current Liabilities	Long-term Debt	Noncurrent Liabilities	Partners' Capital
Downstream Segment	$36,735	$359,156	$40,959	$140,000	$5,971	$208,961
Upstream Segment	21,506	256,634	6,704	—	84	271,352
Midstream Segment	33,963	800,591	25,113	—	191	809,250

(1) On March 1, 2007, we sold our ownership interest in MB Storage to Louis Dreyfus.

NOTE 10. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

Acquisitions

Terminal Assets

On July 14, 2006, we purchased assets from New York LP Gas Storage, Inc. for $10.0 million. The assets, included in our Downstream Segment, consist of two active caverns, one active brine pond, a four bay truck rack, seven above ground storage tanks, and a twelve-spot railcar rack located east of our Watkins Glen, New York facility. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and inventory.

Refined Products Terminal

Effective November 1, 2006, we purchased a refined petroleum product terminal in Aberdeen, Mississippi, for approximately $5.8 million from Mississippi Terminal and Marketing Inc. ("MTMI"). We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price primarily to property, plant and equipment, goodwill and intangible assets. We recorded $1.3 million of goodwill related to this acquisition. The facility, located along the Tennessee-Tombigbee Waterway system, has storage capacity of 130,000 barrels for gasoline and diesel, which are supplied by barge for delivery to local markets, including Tupelo and Columbus, Mississippi. In connection with this acquisition, which we have integrated into our Downstream Segment, we are constructing a new 500,000-barrel terminal in Boligee, Alabama, at a cost of approximately $24.0 million, on an 80-acre site which we are leasing from the Greene County Industrial Development Board under a 60-year agreement. The Boligee terminal site is located approximately two miles from Colonial Pipeline. The new terminal is expected to begin service during the second quarter of 2008.

Cavern Assets

On December 26, 2006, we purchased assets from Vectren Utility Holdings, Inc. for $4.8 million. The assets, included in our Downstream Segment, consist of one active 170,000 barrel LPG storage cavern, the associated piping and related equipment. These assets are located adjacent to our Todhunter facility near Middleton, Ohio and tie into our existing LPG pipeline. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price primarily to property, plant and equipment.

On July 31, 2007, we purchased assets from Duke Energy Ohio, Inc. and Ohio River Valley Propane, LLC for approximately $6.1 million. The assets, included in our Downstream Segment, consist of an active 170,000 barrel LPG storage cavern, the associated piping and related equipment and a one bay truck rack. These assets are located adjacent to our Todhunter facility near Middleton, Ohio and are connected to our existing LPG pipeline. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment.

Crude Oil Pipeline Assets

On September 27, 2007, we purchased assets from Shell Pipeline Company LP for approximately $6.8 million. The assets, included in our Upstream Segment, consisted of approximately 44 miles of pipeline in South Texas and related equipment. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price to property, plant and equipment.

Dispositions

Crude Oil and Refined Products Assets

On October 6, 2006, we sold certain crude oil pipeline assets from our Upstream Segment and refined products pipeline assets from our Downstream Segment in the Houston, Texas area, to an affiliate of Enterprise Products Partners for approximately $11.7 million. These assets, which have been idle since acquisition, were part of assets acquired by us in 2005. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of these pipeline assets was approximately $6.0 million. We recognized a gain of $5.7 million on this transaction, which is included in gain on sale of assets in our statements of consolidated income.

MB Storage and Other Related Assets

On March 1, 2007, TE Products sold its 49.5% ownership interest in MB Storage, its 50% ownership interest in Mont Belvieu Venture, LLC (the general partner of MB Storage) and other related assets to Louis Dreyfus for a total of approximately $155.8 million in cash, which includes approximately $18.5 million for other TE Products assets. This sale was in compliance with the October 2006 order and consent agreement with the FTC and was completed in accordance with the terms and conditions approved by the FTC in February 2007. We used the proceeds from the transaction to partially fund our 2007 portion of the Jonah Phase V expansion and other organic growth projects. We recognized gains of approximately $59.6 million and $13.2 million related to the sale of our equity interests and other related assets of TE Products, respectively, which are included in gain on sale of ownership interest in MB Storage and gain on the sale of assets, respectively, in our statements of consolidated income.

In accordance with a transition services agreement between TE Products and Louis Dreyfus, TE Products will provide certain administrative services to MB Storage for a period of up to two years after the sale, for a fee equal to 110% of the direct costs and expenses TE Products and its affiliates incur to provide the transition services to MB Storage. Payments for these services will be made according to the terms specified in the transition services agreement.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Other Refined Products Assets

On January 23, 2007, we sold a 10-mile, 18-inch diameter segment of pipeline to an affiliate of Enterprise Products Partners for approximately $8.0 million in cash. These assets were part of our Downstream Segment and had a net book value of approximately $2.5 million. The sales proceeds were used to fund construction of a replacement pipeline in the area, in which the new pipeline provides greater operational capability and flexibility. We recognized a gain of approximately $5.5 million on this transaction, which is included in gain on sale of assets in our statements of consolidated income.

Discontinued Operations

Pioneer Plant

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business for us. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and recommended for approval by our ACG Committee and a fairness opinion was rendered by an investment banking firm. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2006 and 2005, are presented below:

	For Year Ended December 31,	
	2006	2005
Operating revenues:		
Sales of petroleum products	$ 3,828	$ 10,479
Other	932	2,975
Total operating revenues	4,760	13,454
Costs and expenses:		
Purchases of petroleum products	3,000	8,870
Operating expense	182	692
Depreciation and amortization	51	612
Taxes – other than income taxes	30	130
Total costs and expenses	3,263	10,304
Income from discontinued operations	$ 1,497	$ 3,150

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net cash provided by discontinued operations for the years ended December 31, 2006 and 2005, are presented below:

	For Year Ended December 31, 2006	2005
Cash flows from discontinued operations:		
Net income	$ 19,369	$ 3,150
Depreciation and amortization	51	612
Gain on sale of Pioneer plant	(17,872)	—
(Increase) decrease in inventories	(27)	20
Net cash provided by discontinued operations	$ 1,521	$ 3,782

NOTE 11. INTANGIBLE ASSETS AND GOODWILL

Intangible Assets

The following table summarizes our intangible assets, including excess investments, being amortized at December 31, 2007 and 2006:

	December 31, 2007		December 31, 2006	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Downstream Segment:				
Transportation agreements	$ 1,000	$ (358)	$ 1,000	$ (308)
Other	4,927	(325)	1,974	(78)
Subtotal	5,927	(683)	2,974	(386)
Upstream Segment:				
Transportation agreements	888	(335)	888	(276)
Other	10,005	(3,046)	10,030	(2,479)
Subtotal	10,893	(3,381)	10,918	(2,755)
Midstream Segment:				
Gathering agreements	239,649	(107,356)	239,649	(86,537)
Fractionation agreements	38,000	(18,525)	38,000	(16,625)
Other	306	(149)	306	(134)
Subtotal	277,955	(126,030)	277,955	(103,296)
Total intangible assets	294,775	(130,094)	291,847	(106,437)
Excess investments: (1)				
Downstream Segment (2)	33,390	(21,861)	33,390	(16,579)
Upstream Segment (3)	26,908	(5,135)	26,908	(4,450)
Midstream Segment (4)	6,988	(95)	2,924	—
Subtotal	67,286	(27,091)	63,222	(21,029)
Total intangible assets, including excess investments	$ 362,061	$ (157,185)	$ 355,069	$ (127,466)

(1) Excess investments are included in “Equity Investments” in our Consolidated Balance Sheets.

(2) Relates to our investment in Centennial Pipeline LLC.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(3) Relates to our investment in Seaway Crude Pipeline Company.

(4) Relates to our investment in Jonah Gas Gathering Company.

The following table presents the amortization expense of our intangible assets by segment for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Intangible assets:			
Downstream Segment	$ 628	$ 59	$ 66
Upstream Segment	652	716	992
Midstream Segment	22,734	28,044	29,466
Subtotal	24,014	28,819	30,524
Excess investments: (1)			
Downstream Segment	5,282	3,632	4,072
Upstream Segment	685	686	691
Midstream Segment	95	—	—
Subtotal	6,062	4,318	4,763
Total amortization expense	$ 30,076	$ 33,137	$ 35,287

(1) Amortization of excess investments is included in equity earnings.

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required.

The values assigned to our intangible assets for natural gas gathering contracts on the Val Verde system are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts. From time to time, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the system, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. Further revisions to these estimates may occur as additional production information is made available to us.

The values assigned to our fractionation agreement and other intangible assets are generally amortized on a straight-line basis. Our fractionation agreement is being amortized over its contract period of 20 years. The amortization periods for our other intangible assets, which include non-compete and other agreements, range from 3 years to 15 years. The value of $8.7 million assigned to our crude supply and transportation intangible customer contracts is being amortized on a unit-of-production basis.

The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life. The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years. The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline. The value assigned to our excess investment in Jonah was created as a result of interest capitalized on the construction of Jonah’s expansion. We will continue to capitalize interest on the construction of the expansion of the Jonah system until the construction is completed and placed into service. As portions of the expansion are placed into service, we amortize the excess investment in Jonah on a straight-line basis over the life of the assets constructed.

The following table sets forth the estimated amortization expense of intangible assets and the estimated amortization expense allocated to equity earnings for the years ending December 31:

	Intangible Assets	Excess Investments
2008	$21,825	$5,097
2009	19,531	3,467
2010	17,598	3,171
2011	15,909	1,019
2012	14,309	947

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill, but instead requires testing for impairment at least annually. We test goodwill for impairment annually at December 31.

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

The following table presents the carrying amount of goodwill at December 31, 2007 and 2006, by business segment:

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill:				
December 31, 2007	$1,339	$—	$14,167	$15,506
December 31, 2006	1,339	—	14,167	15,506

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 12. DEBT OBLIGATIONS

The following table summarizes the principal amounts outstanding under all of our debt instruments at December 31, 2007 and 2006:

	December 31, 2007	December 31, 2006
Short-term senior debt obligations:		
6.45% TE Products Senior Notes, due January 2008 (1)	$ 180,000	$ —
7.51% TE Products Senior Notes, due January 2028 (1)	175,000	—
Total principal amount of short-term senior debt obligations	355,000	—
Adjustment to carrying value associated with hedges of fair value and unamortized discounts (2)	(1,024)	—
Total short-term senior debt obligations	$ 353,976	$ —
Long-term:		
Senior debt obligations:		
Revolving Credit Facility, due December 2012	$ 490,000	$ 490,000
6.45% TE Products Senior Notes, due January 2008	—	180,000
7.625% Senior Notes, due February 2012	500,000	500,000
6.125% Senior Notes, due February 2013	200,000	200,000
7.51% TE Products Senior Notes, due January 2028 (1)	—	210,000
Total principal amount of long-term senior debt obligations	1,190,000	1,580,000
7.000% Junior Subordinated Notes, due June 2067	300,000	—
Total principal amount of long-term debt obligations	1,490,000	1,580,000
Adjustment to carrying value associated with hedges of fair value and unamortized discounts (3)	21,083	23,287
Total long-term debt obligations	1,511,083	1,603,287
Total Debt Instruments (3)	$ 1,865,059	$ 1,603,287
Standby letter of credit outstanding (4)	$ 23,494	$ 8,700

(1) On January 28, 2008, TE Products redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. Additionally, the 6.45% TE Products Senior Notes matured on January 15, 2008.

(2) Includes $1.0 million related to fair value hedges and $2 thousand in unamortized discount.

(3) We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the debt obligations presented above (see Note 6). At December 31, 2007 and 2006, amount includes $2.1 million and $2.0 million of unamortized discounts, respectively, and $23.2 million and $25.3 million related to fair value hedges, respectively.

(4) Letters of credit were issued in connection with crude oil purchased during the respective year. Payables related to these purchases of crude oil are generally paid during the following quarter.

Revolving Credit Facility

We had in place a $700.0 million unsecured revolving credit facility, including the issuance of letters of credit (“Revolving Credit Facility”), which matured on December 13, 2011. On December 18, 2007, we amended the Revolving Credit Facility (“Fifth Amendment”). The maturity date was extended to December 12, 2012, and the Fifth Amendment allows us to request unlimited one-year extensions of the maturity date, subject to lender approval and satisfaction of certain other conditions. The Fifth Amendment contains an accordion feature whereby the total amount of the bank commitments may be increased, with lender approval and the satisfaction of certain other conditions, from $700.0 million up to a maximum amount of $1.0 billion. The Fifth Amendment also increased the aggregate outstanding principal amount of swing line loans or same day borrowings permitted under the Revolving Credit Facility from $25.0 million to $40.0 million. The interest rate is based, at our option, on either the lender’s base rate, or LIBOR rate, plus a margin, in effect at the time of the borrowings. The applicable margin with respect to LIBOR rate borrowings is based on our senior unsecured non-credit enhanced long-term debt rating issued by

Standard & Poor's Rating Services and Moody's Investors Service, Inc. The Fifth Amendment added a term-out option to the Revolving Credit Facility in which we may, on the maturity date, convert the principal balance of all revolving loans then outstanding into a non-revolving one-year term loan. Upon the conversion of the revolving loans to term loans pursuant to the term-out option, the applicable LIBOR spread will increase by 0.125% per year, and if immediately prior to such borrowing the total outstanding revolver borrowings then outstanding exceeds 50% of the total lender commitments, the applicable LIBOR spread with respect to borrowings will increase by an additional 10 basis points.

Prior to the effectiveness of the Fifth Amendment, the Revolving Credit Facility contained financial covenants that required us to maintain (i) a ratio of EBITDA to Interest Expense (as defined and calculated in the facility) of at least 3.00 to 1.00 and (ii) a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 4.75 to 1.00 (subject to adjustment for specified acquisitions), in each case with respect to specified twelve month periods. The Fifth Amendment eliminated the interest coverage requirement and provides us additional flexibility with respect to our leverage test by increasing the threshold ratio of Consolidated Funded Debt to Pro Forma EBITDA to 5.00 to 1.00 (and, if after giving effect to a permitted acquisition the ratio exceeds 5.00 to 1.00, the threshold ratio will be increased to 5.50 to 1.00 for the fiscal quarter in which such acquisition occurs and the first full fiscal quarter following such acquisition. Other restrictive covenants in the Revolving Credit Facility limit our ability, and the ability of certain of our subsidiaries, to, among other things, incur certain additional indebtedness, make distributions in excess of Available Cash (see Note 13), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. The credit agreement restricts the amount of outstanding debt of the Jonah joint venture to debt owing to the owners of its partnership interests and other third-party debt in the aggregate principal amount of $50.0 million and allows for the issuance of certain hybrid securities of up to 15% of our Consolidated Total Capitalization (as defined therein). Our obligations under the Revolving Credit Facility are guaranteed by the Subsidiary Guarantors (defined below). At December 31, 2007, $490.0 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 5.71%. At December 31, 2007, we were in compliance with the covenants of the Revolving Credit Facility.

Senior Notes

On January 27, 1998, TE Products issued $180.0 million principal amount of 6.45% Senior Notes due 2008 and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively the "TE Products Senior Notes"). Interest on the TE Products Senior Notes was payable semiannually in arrears on January 15 and July 15 of each year. The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and were being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 were redeemed at maturity on January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, became redeemable at any time after January 15, 2008, at the option of TE Products, in whole or in part, at varying fixed annual redemption prices. In October 2007, TE Products repurchased $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest. We funded the redemption with borrowings under our Revolving Credit Facility. On January 28, 2008, TE Products redeem the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption.

On February 20, 2002 and January 30, 2003, we issued $500.0 million principal amount of 7.625% Senior Notes due 2012 ("7.625% Senior Notes") and $200.0 million principal amount of 6.125% Senior Notes due 2013 ("6.125% Senior Notes"), respectively. The 7.625% Senior Notes and the 6.125% Senior Notes were issued at discounts of $2.2 million and $1.4 million, respectively, and are being accreted to their face value over the applicable term of the senior notes. The senior notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indentures governing our senior notes contain covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indentures do not limit our ability to incur additional indebtedness. At December 31, 2007, we were in compliance with the covenants of these senior notes.

Junior Subordinated Notes

In May 2007, we issued and sold $300.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due June 1, 2067 (“Junior Subordinated Notes”). We used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under our Revolving Credit Facility and for general partnership purposes. Our payment obligations under the Junior Subordinated Notes are subordinated to all of our current and future senior indebtedness (as defined in the related indenture). TE Products, TEPPCO Midstream, TCTM and Val Verde (collectively, the “Subsidiary Guarantors”) have issued full, unconditional, and joint and several guarantees, on a junior subordinated basis, of payment of the principal of, premium, if any, and interest on the Junior Subordinated Notes.

The indenture governing the Junior Subordinated Notes does not limit our ability to incur additional debt, including debt that ranks senior to or equally with the Junior Subordinated Notes. The indenture allows us to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture also provides that during any period in which we defer interest payments on the Junior Subordinated Notes, subject to certain exceptions, (i) we cannot declare or make any distributions with respect to, or redeem, purchase or make a liquidation payment with respect to, any of our equity securities; (ii) neither we nor the Subsidiary Guarantors will make, and we and the Subsidiary Guarantors will cause our respective majority-owned subsidiaries not to make, any payment of interest, principal or premium, if any, on or repay, purchase or redeem any of our or the Subsidiary Guarantors’ debt securities (including securities similar to the Junior Subordinated Notes) that contractually rank equally with or junior to the Junior Subordinated Notes or the guarantees, as applicable; and (iii) neither we nor the Subsidiary Guarantors will make, and we and the Subsidiary Guarantors will cause our respective majority-owned subsidiaries not to make, any payments under a guarantee of debt securities (including under a guarantee of debt securities that are similar to the Junior Subordinated Notes) that contractually ranks equally with or junior to the Junior Subordinated Notes or the guarantees, as applicable.

The Junior Subordinated Notes bear interest at a fixed annual rate of 7.000% from May 2007 to June 1, 2017, payable semi-annually in arrears on June 1 and December 1 of each year, commencing December 1, 2007. After June 1, 2017, the Junior Subordinated Notes will bear interest at a variable annual rate equal to the 3-month LIBOR rate for the related interest period plus 2.7775%, payable quarterly in arrears on March 1, June 1, September 1 and December 1 of each year commencing September 1, 2017. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. Deferred interest will accumulate additional interest at the then-prevailing interest rate on the Junior Subordinated Notes. The Junior Subordinated Notes mature in June 2067. The Junior Subordinated Notes are redeemable in whole or in part prior to June 1, 2017 for a “make-whole” redemption price and thereafter at a redemption price equal to 100% of their principal amount plus accrued interest. The Junior Subordinated Notes are also redeemable prior to June 1, 2017 in whole (but not in part) upon the occurrence of certain tax or rating agency events at specified redemption prices. At December 31, 2007, we were in compliance with the covenants of the Junior Subordinated Notes.

In connection with the issuance of the Junior Subordinated Notes, we and our Subsidiary Guarantors entered into a replacement capital covenant in favor of holders of a designated series of senior long-term indebtedness (as provided in the underlying documents) pursuant to which we and our Subsidiary Guarantors agreed for the benefit of such debt holders that we would not redeem or repurchase or otherwise satisfy, discharge or defease any of the Junior Subordinated Notes on or before June 1, 2037, unless, subject to certain limitations, during the 180 days prior to the date of that redemption, repurchase, defeasance or purchase, we have or one of our subsidiaries has received a specified amount of proceeds from the sale of qualifying securities that have characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior

Subordinated Notes. The replacement capital covenant is not a term of the indenture or the Junior Subordinated Notes.

Fair Values

The following table summarizes the estimated fair values of the Senior Notes and Junior Subordinated Notes at December 31, 2007 and 2006:

		Fair Value December 31,	
	Face Value	2007	2006
6.45% TE Products Senior Notes, due January 2008 (1)	$180,000	$179,982	$181,641
7.625% Senior Notes, due February 2012	500,000	536,765	537,067
6.125% Senior Notes, due February 2013	200,000	202,027	201,610
7.51% TE Products Senior Notes, due January 2028 (1)	175,000	181,571	221,471
7.000% Junior Subordinated Notes, due June 2067	300,000	270,485	—

(1) In October 2007, TE Products redeemed $35.0 million principal amount of the 7.51% TE Products Senior Notes for $36.1 million and accrued interest, and on January 28, 2008, TE Products redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. Additionally, the $180.0 million principal amount of 6.45% TE Products Senior Notes matured and was repaid on January 15, 2008. We funded the retirement of both series with borrowings under our term credit agreement (see Note 22). The face value of the 7.51% TE Products Senior Notes at December 31, 2006 was $210.0 million.

Short-Term Credit Facility

On December 21, 2007, we entered into a senior unsecured term credit agreement (“Term Credit Agreement”), with a borrowing capacity of $1.0 billion that matures on December 19, 2008. Term loans may be drawn in up to five separate drawings, each in a minimum amount of $75.0 million. Amounts repaid may not be re-borrowed, and the principal amount of all term loans are due and payable in full on the maturity date. We are required to make mandatory principal repayments on the outstanding term loans from 100% of the net cash proceeds we receive from (i) any asset sale excluding asset sales made in the ordinary course of business and sales to the extent aggregate proceeds are less than $25.0 million, and (ii) subject to specified exceptions, issuances of debt or equity. The interest rate is based, at our option, on either the lender’s base rate, or LIBOR rate, plus a margin, in effect at the time of the borrowings. The applicable margin with respect to LIBOR rate borrowings is based on our senior unsecured non-credit enhanced long-term debt rating issued by Standard & Poor’s Rating Services and Moody’s Investors Service, Inc. Financial covenants in the Term Credit Agreement require us to maintain a ratio of Consolidated Funded Debt to Pro Forma EBTIDA (as defined and calculated in the facility) of less than 5.00 to 1.00 (subject to adjustment for specified acquisitions, as described above with respect to our Revolving Credit Facility). Other restrictive covenants in the Term Credit Agreement limit our ability, and the ability of certain of our subsidiaries, to, among other things, incur certain indebtedness, make distributions in excess of Available Cash (see Note 13), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. Our obligations under the Term Credit Agreement are guaranteed by the Subsidiary Guarantors. At December 31, 2007, no amounts were outstanding under the Term Credit Agreement, and we were in compliance with the covenants of the Term Credit Agreement.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Debt Obligations of Unconsolidated Affiliates

We have one unconsolidated affiliate, Centennial, with long-term debt obligations. The following table shows the total debt of Centennial at December 31, 2007 (on a 100% basis to the affiliate) and the corresponding scheduled maturities of such debt.

	Scheduled Maturities of Debt
2008	$ 10,100
2009	9,900
2010	9,100
2011	9,000
2012	8,900
After 2012	93,000
Total scheduled maturities of debt	$ 140,000

At December 31, 2007 and 2006, Centennial's debt obligations consisted of $140.0 million borrowed under a master shelf loan agreement, and $150.0 million ($140.0 million borrowed under a master shelf loan agreement and $10.0 million borrowed under an additional credit agreement, which terminated in April 2007), respectively. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed by Centennial's owners.

TE Products and its joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial defaults on its debt obligations, the estimated payment obligation for TE Products is $70.0 million. At December 31, 2007, TE Products has recorded a liability of $9.5 million related to its guarantee of Centennial's debt (see Note 17).

NOTE 13. PARTNERS' CAPITAL AND DISTRIBUTIONS

Our Units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Partnership Agreement. We are managed by our General Partner.

In accordance with the Partnership Agreement, capital accounts are maintained for our General Partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements. In connection with the amendment of our Partnership Agreement in December 2006, the General Partner's obligation to make capital contributions to maintain its 2% capital account was eliminated.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and General Partner will receive. Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period. This is generally consistent with the manner of allocating net income under our Partnership Agreement. Net income determined under our Partnership Agreement, however, incorporates principles established for U.S. federal income tax purposes and is not comparable to net income reflected under GAAP in our financial statements.

Equity Offerings and Registration Statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by our General Partner in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission ("SEC") that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $2.0 billion of equity securities, debt securities or a combination thereof. In May 2007, we sold $300.0 million in principal amount of Junior Subordinated Notes under our universal shelf registration statement. For additional information regarding this debt offering, see Note 12. After taking into account past issuances of securities under this registration statement, as of December 31, 2007, we have the ability to issue approximately $1.2 billion of additional securities under this registration statement, subject to customary marketing terms and conditions.

In July 2006, we issued and sold in an underwritten public offering 5.0 million Units at a price to the public of $35.50 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $170.4 million. On July 12, 2006, 750,000 additional Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. Proceeds from the over-allotment sale, net of underwriting discount, totaled $25.6 million. The net proceeds from the offering and the over-allotment were used to reduce indebtedness under our Revolving Credit Facility.

In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 5,000,000 Units in connection with the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (see Note 4), which provides for awards of our Units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. In June 2007, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 Units in connection with the EPCO, Inc. TPP Employee Unit Purchase Plan (see "EPCO, Inc. TPP Employee Unit Purchase Plan" below).

In September 2007, we filed a registration statement with the SEC authorizing the issuance of up to 10,000,000 Units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides owners of our Units a voluntary means by which they can increase the number of Units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional Units. Units purchased through the DRIP may be acquired at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. As of December 31, 2007, 39,796 Units have been issued in connection with the DRIP.

Quarterly Distributions of Available Cash

We make quarterly cash distributions of all of our available cash, generally defined in our Partnership Agreement as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its reasonable discretion ("Available Cash"). Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as shown in the following table. Effective December 8, 2006, upon approval of our unitholders, our Partnership Agreement was amended and the 50%/50% distribution tier was eliminated in exchange for the issuance of 14,091,275 Units to the General Partner (see Note 1).

	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%
Over First Target – Cash distributions greater than $0.325 per Unit	75%	25%

The following table reflects the allocation of total distributions paid during the years ended December 31, 2007, 2006 and 2005.

	For Year Ended December 31, 2007	2006	2005
Limited Partner Units (1)	$ 246,152	$ 196,665	$ 177,916
General Partner Ownership Interest	5,024	4,014	3,630
General Partner Incentive	43,274	77,887	69,555
Total Cash Distributions Paid	$ 294,450	$ 278,566	$ 251,101
Total Cash Distributions Paid Per Unit	$ 2.74	$ 2.70	$ 2.68

(1) The 2007 amount includes $38.6 million of distributions paid to affiliates of our General Partner with respect to the 14.1 million Units we issued in December 2006.

Our quarterly cash distributions for 2006 and 2007 are presented in the following table:

	Cash Distribution History: Distribution per Unit	Record Date	Payment Date
2006			
1st Quarter	$0.6750	Apr. 28, 2006	May 5, 2006
2nd Quarter	0.6750	Jul. 31, 2006	Aug. 7, 2006
3rd Quarter	0.6750	Oct. 31, 2006	Nov. 7, 2006
4th Quarter	0.6750	Jan. 31, 2007	Feb. 7, 2007
2007			
1st Quarter	$0.6850	Apr. 28, 2007	May 7, 2007
2nd Quarter	0.6850	Jul. 31, 2007	Aug. 7, 2007
3rd Quarter	0.6950	Oct. 31, 2007	Nov. 7, 2007
4th Quarter (1)	0.6950	Jan. 31, 2008	Feb. 7, 2008

(1) The fourth quarter 2007 cash distribution totaled approximately $74.9 million.

EPCO, Inc. TPP Employee Unit Purchase Plan

At a special meeting of our unitholders on December 8, 2006, our unitholders approved the EPCO, Inc. TPP Employee Unit Purchase Plan (the “Unit Purchase Plan”), which provides for discounted purchases of our Units by employees of EPCO and its affiliates. Generally, any employee who (1) has been employed by EPCO or any of its designated affiliates for at least three consecutive months, (2) is a regular, active and full time employee and (3) is regularly scheduled to work at least 30 hours per week is eligible to participate in the Unit Purchase Plan, provided that employees covered by collective bargaining agreements (unless otherwise specified therein), any temporary, project or leased employee or any nonresident alien and 5% owners of us, EPCO or any affiliate are not eligible to participate.

A maximum of 1,000,000 Units may be delivered under the Unit Purchase Plan (subject to adjustment as provided in the plan). Units to be delivered under the plan may be acquired by the custodian of the plan in the open market or directly from us, EPCO, any of EPCO’s affiliates or any other person; however, it is generally intended that Units are to be acquired from us. Eligible employees may elect to have a designated whole percentage (ranging from 1% to 10%) of their eligible compensation for each pay period withheld for the purchase of Units under the plan. EPCO and its affiliated employers will periodically remit to the custodian the withheld amounts, together with an additional amount by which EPCO will bear approximately 10% of the cost of the Units for the benefit of the participants. Unit purchases will be made following three month purchase periods over which the withheld amounts are to be accumulated. We reimburse EPCO for all such costs allocated to employees who work in our business (see Note 15).

The plan is administered by a committee appointed by the Chairman or Vice Chairman of EPCO. The Unit Purchase Plan may be amended or terminated at any time by the board of directors of EPCO, or the Chairman of the Board or Vice Chairman of the Board of EPCO; however, any material amendment, such as a material increase in the number of Units available under the plan or an increase in the employee discount amount, would also require the approval of at least 50% of our unitholders. The Unit Purchase Plan is effective until December 8, 2016, or, if earlier, at the time that all available Units under the plan have been purchased on behalf of the participants or the time of termination of the plan by EPCO or the Chairman or Vice Chairman of EPCO. As of December 31, 2007, 4,507 Units have been issued to employees under this plan.

General Partner's Interest

At December 31, 2007 and 2006, we had deficit balances of $88.0 million and $85.7 million, respectively, in our General Partner's equity account. These negative balances do not represent assets to us and do not represent obligations of the General Partner to contribute cash or other property to us. The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Statements of Consolidated Partners' Capital for a detail of the General Partner's equity account). For the years ended December 31, 2007, 2006 and 2005, our General Partner was allocated $46.0 million (representing 16.47%), $57.7 million (representing 28.57%) and $47.6 million (representing 29.27%), respectively, of our net income and received $48.3 million, $81.9 million and $73.2 million, respectively, in cash distributions.

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its reasonable discretion. Cash distributions in excess of net income allocations and capital contributions during previous years resulted in a deficit in the General Partner's equity account at December 31, 2007 and 2006. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

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

Accumulated Other Comprehensive Income (Loss)

SFAS No. 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, gains or losses associated with pension or other postretirement benefits, prior service costs or credits associated with pension or other postretirement benefits, transition assets or obligations associated with pension or other postretirement benefits and unrealized gains and losses on certain investments in debt and equity securities to be reported in a financial statement. As of and for the year ended December 31, 2007, the components of accumulated other comprehensive income reflected on our consolidated balance sheets were composed of crude oil hedges, interest rate swaps, treasury locks and unrecognized losses associated with the TEPPCO RCBP. The series of crude oil hedges have forward positions throughout 2008. While the crude oil hedges are in effect, changes in their fair values, to the extent the hedges are effective, are recognized in accumulated other comprehensive income until they are recognized in net income in future periods. The interest rate swaps mature in January 2008, are related to our variable rate Revolving Credit Facility and were de-designated as cash flow hedges on June 30, 2007 (see Note 6). The proceeds from the termination of the treasury locks are being amortized into earnings over the terms of the respective debt (see Note 6).

The accumulated balance of other comprehensive income (loss) is as follows:

Balance at December 31, 2004	$ —
Change in fair value of cash flow hedge	11
Balance at December 31, 2005	11
Transferred to earnings	2,255
Changes in fair values of interest rate cash flow hedges	(2,503)
Changes in fair values of crude oil cash flow hedges	730
Adjustment to initially apply SFAS No. 158	(67)
Balance at December 31, 2006	426
Changes in fair values of interest rate cash flow hedges and transfer of interest rate swaps to earnings	249
Changes in fair values of crude oil cash flow hedges	(19,382)
Proceeds from termination of treasury locks	1,443
Amortization of treasury lock proceeds into earnings	(64)
Changes in fair values of treasury locks	(25,296)
Pension benefit SFAS No. 158 adjustment	67
Balance at December 31, 2007	$ (42,557)

NOTE 14. BUSINESS SEGMENTS

Through December 31, 2007, we have three reporting segments:

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

On February 1, 2008, with the acquisition of the marine transportation business, we began operating and reporting in a fourth business segment, Marine Transportation Segment (see Note 22).

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

Our Downstream Segment revenues are earned from transportation, marketing and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. We generally realize higher revenues in the Downstream Segment during the first and fourth quarters of each year since LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. 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. The two largest operating expense items of the Downstream Segment are labor and electric power. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in MB Storage, which we sold on March 1, 2007 (see Note 10), and in Centennial (see Note 9).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Our Upstream Segment revenues are earned from gathering, transporting, marketing and storing crude oil and distributing lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale or delivery of the crude oil to local refineries, marketers or other end users. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas. Our Upstream Segment also includes our equity investment in Seaway (see Note 9). Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas. Additionally, we completed a project in our South Texas system that allows Seaway to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing.

Our Midstream Segment revenues are earned from the gathering of coal bed methane and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde; transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; and the fractionation of NGLs in Colorado. Our Midstream Segment also includes our equity investment in Jonah (see Note 9). Jonah, which is a joint venture between us and an affiliate of Enterprise Products Partners, owns a natural gas gathering system in the Green River Basin in southwestern Wyoming. Prior to August 1, 2006, when Jonah was wholly-owned by us, operating results for Jonah were included in the consolidated Midstream Segment operating results. Effective August 1, 2006, we entered into the joint venture with Enterprise Products Partners' affiliate, upon which Jonah was deconsolidated, and its operating results since August 1, 2006, have been accounted for under the equity method of accounting. Operating results of the Pioneer plant, which we sold to an Enterprise Products Partners' affiliate in March 2006, are shown as discontinued operations for the years ended December 31, 2006 and 2005.

The following table presents our measurement of earnings before interest expense for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Total operating revenues	$9,658,060	$9,607,485	$8,605,034
Less: Total costs and expenses	9,408,505	9,377,706	8,385,001
Operating income	249,555	229,779	220,033
Add: Gain on sale of ownership interest in MB Storage	59,628	—	—
Equity earnings	68,755	36,761	20,094
Interest income	1,676	2,077	687
Other income — net	1,346	888	448
Earnings before interest expense, provision for income taxes and discontinued operations	$ 380,960	$ 269,505	$ 241,262

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

A reconciliation of our earnings before interest expense, provision for income taxes and discontinued operations to net income for the years ended December 31, 2007, 2006 and 2005 is as follows:

	For Year Ended December 31, 2007	2006	2005
Earnings before interest expense, provision for income taxes and discontinued operations	$ 380,960	$ 269,505	$ 241,262
Interest expense — net	(101,223)	(86,171)	(81,861)
Income before provision for income taxes	279,737	183,334	159,401
Provision for income taxes	557	652	—
Income from continuing operations	279,180	182,682	159,401
Discontinued operations	—	19,369	3,150
Net income	$ 279,180	$ 202,051	$ 162,551

The table below includes information by segment, together with reconciliations to our consolidated totals for the periods indicated:

	Downstream Segment	Upstream Segment	Midstream Segment	Partnership and Other	Consolidated
Revenues from third parties:					
Year ended December 31, 2007	$ 355,495	$ 9,172,707	$ 109,082	$ —	$ 9,637,284
Year ended December 31, 2006	298,866	9,108,283	181,486	—	9,588,635
Year ended December 31, 2005	280,565	8,106,781	194,648	—	8,581,994
Revenues from related parties:					
Year ended December 31, 2007	$ 7,196	$ 896	$ 13,153	$ (469)	$ 20,776
Year ended December 31, 2006	5,435	598	13,137	(320)	18,850
Year ended December 31, 2005	6,626	3,135	13,279	—	23,040
Intersegment and intrasegment revenues:					
Year ended December 31, 2007	$ —	$ 80	$ —	$ (80)	$ —
Year ended December 31, 2006	—	748	6,646	(7,394)	—
Year ended December 31, 2005	—	323	3,244	(3,567)	—
Total revenues:					
Year ended December 31, 2007	$ 362,691	$ 9,173,683	$ 122,235	$ (549)	$ 9,658,060
Year ended December 31, 2006	304,301	9,109,629	201,269	(7,714)	9,607,485
Year ended December 31, 2005	287,191	8,110,239	211,171	(3,567)	8,605,034
Depreciation and amortization:					
Year ended December 31, 2007	$ 46,141	$ 18,257	$ 40,827	$ —	$ 105,225
Year ended December 31, 2006	41,405	14,400	52,447	—	108,252
Year ended December 31, 2005	39,403	17,161	54,165	—	110,729
Operating income:					
Year ended December 31, 2007	$ 135,055	$ 84,222	$ 25,767	$ 4,511	$ 249,555
Year ended December 31, 2006	91,262	70,840	65,499	2,178	229,779
Year ended December 31, 2005	88,143	33,174	98,716	—	220,033
Equity earnings (losses):					
Year ended December 31, 2007	$ (12,396)	$ 2,602	$ 83,060	$ (4,511)	$ 68,755
Year ended December 31, 2006	(8,018)	11,905	35,052	(2,178)	36,761
Year ended December 31, 2005	(2,984)	23,078	—	—	20,094

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Downstream Segment	Upstream Segment	Midstream Segment	Partnership and Other	Consolidated
Earnings before interest expense, provision for income taxes and discontinued operations:					
Year ended December 31, 2007	$ 184,251	$ 87,246	$ 109,463	$ —	$ 380,960
Year ended December 31, 2006	84,746	83,540	101,219	—	269,505
Year ended December 31, 2005	85,914	56,408	98,940	—	241,262
Segment assets:					
At December 31, 2007	$ 1,221,316	$ 2,084,830	$ 1,512,621	$ (68,710)	$ 4,750,057
At December 31, 2006	1,160,929	1,504,699	1,335,502	(79,038)	3,922,092
At December 31, 2005	1,056,217	1,353,492	1,280,548	(9,719)	3,680,538
Capital expenditures:					
At December 31, 2007	$ 165,353	$ 54,583	$ 7,412	$ 924	$ 228,272
At December 31, 2006	75,344	48,351	42,929	3,422	170,046
At December 31, 2005	58,609	40,954	119,837	1,153	220,553
Investments in unconsolidated affiliates:					
At December 31, 2007	$ 79,324	$ 188,650	$ 879,021	$ —	$ 1,146,995
At December 31, 2006	148,316	195,584	695,810	—	1,039,710
At December 31, 2005	157,335	202,321	—	—	359,656
Intangible assets:					
At December 31, 2007	$ 5,244	$ 7,512	$ 151,925	$ —	$ 164,681
At December 31, 2006	2,588	8,163	174,659	—	185,410
At December 31, 2005	1,001	8,441	367,466	—	376,908
Goodwill:					
At December 31, 2007	$ 1,339	$ 14,167	$ —	$ —	$ 15,506
At December 31, 2006	1,339	14,167	—	—	15,506
At December 31, 2005	—	14,167	2,777	—	16,944

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 15. RELATED PARTY TRANSACTIONS

The following table summarizes the related party transactions for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Revenues from EPCO and affiliates (1):			
Sales of petroleum products (2)	$ 320	$ 3,165	$ 11
Transportation — NGLs (3)	13,153	10,225	7,433
Transportation — LPGs (4)	5,191	3,648	4,292
Other operating revenues (5)	1,761	1,517	259
Revenues from unconsolidated affiliates:			
Other operating revenues (6)	351	295	312
Costs and Expenses from EPCO and affiliates (1):			
Purchases of petroleum products (7)	61,596	52,982	65,716
Operating expense (8)	96,947	103,924	3,397
General and administrative (9)	25,500	21,709	12,250
Costs and Expenses from unconsolidated affiliates:			
Purchases of petroleum products (10)	5,493	2,987	1,507
Operating expense (11)	8,736	5,094	5,635
Revenues from DCP and affiliates (12):			
Sales of petroleum products	—	—	4,335
Transportation — NGLs	—	—	2,810
Gathering — Natural gas — Jonah	—	—	529
Transportation — LPGs	—	—	732
Other operating revenues	—	—	2,327
Costs and Expenses from DCP and affiliates (12):			
Purchases of petroleum products (13)	—	—	38,533
Operating expense (14) (15) (16)	—	—	17,294

(1) Operating revenues earned and expenses incurred from activities with EPCO and its affiliates are considered related party transactions beginning February 24, 2005, as a result of the change in ownership of the General Partner.

(2) Include sales from Lubrication Services, LLC ("LSI") to Enterprise Products Partners and certain of its subsidiaries. In addition, 2006 includes Jonah NGL sales through July 31, 2006 of $2.9 million to Enterprise Gas Processing, LLC.

(3) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines from Enterprise Products Partners and certain of its subsidiaries.

(4) Includes revenues from LPG transportation on the TE Products pipeline of $5.0 million from Enterprise Products Partners and certain of its subsidiaries and $0.2 million from Energy Transfer Equity, L.P. (see further discussion below).

(5) Includes other operating revenues on the TE Products pipeline and the Val Verde system from Enterprise Products Partners and certain of its subsidiaries.

(6) Includes management fees and rental revenues.

(7) Includes TCO purchases of condensate of $45.1 million, $41.6 million and $3.3 million for the years ended December 31, 2007, 2006 and 2005, respectively, and expenses related to LSI's use of an affiliate of EPCO as a transporter. In addition, 2006 includes $0.1 million of Jonah processing fees through July 31, 2006.

(8) Includes operating payroll, payroll related expenses and other operating expenses, including reimbursements related to employee benefits and employee benefit plans, incurred by EPCO in managing us and our subsidiaries in accordance with the ASA. Also includes insurance expense for the years ended December 31, 2007, 2006 and 2005, related to

premiums paid by EPCO of $13.6 million, $15.8 million and $9.8 million, respectively. Beginning February 24, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO.

(9) Includes administrative payroll, payroll related expenses and other administrative expenses, including reimbursements related to employee benefits and employee benefit plans, incurred by EPCO in managing and operating us and our subsidiaries in accordance with the ASA.

(10) Includes pipeline transportation expense.

(11) Includes rental expense and other operating expense.

(12) Operating revenues earned and expenses incurred from activities with DCP and its affiliates are considered related party transactions prior to February 23, 2005, at which time a change in ownership of the General Partner occurred.

(13) Includes TCO purchases of condensate of $37.7 million and Jonah's Pioneer plant purchases of $0.8 million, which is classified as income from discontinued operations in the consolidated financial statements.

(14) Includes operating costs and expenses related to DCP managing and operating the Jonah and Val Verde systems and the Chaparral NGL pipeline on our behalf under contractual agreements established at the time of acquisition of each asset. In connection with the change in ownership of our General Partner, we or EPCO have assumed these activities.

(15) Includes administrative costs related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

(16) Includes insurance expense related to premiums paid to Bison Insurance Company Limited ("Bison"), a wholly owned subsidiary of Duke Energy, of $1.2 million. Through February 23, 2005, we contracted with Bison for a majority of our insurance coverage, including property, liability, auto and directors and officers' liability insurance.

The following table summarizes the related party balances at December 31, 2007 and 2006:

	December 31,	
	2007	2006
Accounts receivable, related parties (1)	$ 6,525	$11,788
Gas imbalance receivable	—	1,278
Accounts payable, related parties (2)	38,980	34,461
Deferred revenue, related parties	—	252
Other liabilities, related party (3)	—	1,814

(1) Relates to sales and transportation services provided to Enterprise Products Partners and certain of its subsidiaries and EPCO and certain of its affiliates and direct payroll, payroll related costs and other operational expenses charged to unconsolidated affiliates.

(2) Relates to direct payroll, payroll related costs and other operational related charges from Enterprise Products Partners and certain of its subsidiaries and EPCO and certain of its affiliates, transportation and other services provided by unconsolidated affiliates and advances from Seaway for operating expenses.

(3) Relates to our share of EPCO's Oil Insurance Limited insurance program retrospective premiums obligation.

Relationship with EPCO and Affiliates

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

- EPCO and its consolidated private company subsidiaries;
- Texas Eastern Products Pipeline Company, LLC, our General Partner;
- Enterprise GP Holdings, which owns and controls our General Partner;

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

- Enterprise Products Partners, which is controlled by affiliates of EPCO, including Enterprise GP Holdings;
- Duncan Energy Partners, which is controlled by affiliates of EPCO; and
- Enterprise Gas Processing, LLC, which is controlled by affiliates of EPCO and is our joint venture partner in Jonah.

Dan L. Duncan directly owns and controls EPCO and through Dan Duncan LLC, owns and controls EPE Holdings, the general partner of Enterprise GP Holdings. Enterprise GP Holdings owns all of the membership interests of our General Partner. The principal business activity of our General Partner is to act as our managing partner. The executive officers of our General Partner are employees of EPCO (see Note 1).

We and our General Partner are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO and its consolidated private company subsidiaries and affiliates depend on the cash distributions they receive from our General Partner and other investments to fund their operations and to meet their debt obligations. We paid cash distributions of $48.3 million, $81.9 million and $73.2 million, during the years ended December 31, 2007, 2006 and 2005, respectively, to our General Partner.

The limited partner interests in us that are owned or controlled by EPCO and certain of its affiliates, other than those interests owned by Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an affiliate of EPCO. All of the membership interests in our General Partner and the limited partner interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. If Enterprise GP Holdings were to default under its credit facility, its lender banks could own our General Partner.

Unless noted otherwise, our transactions and agreements with EPCO or its affiliates are not on an arm’s length basis. As a result, we cannot provide assurance that the terms and provisions of such transactions or agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

We do not have any employees. We are managed by our General Partner, and all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to the ASA or by other service providers. We reimburse EPCO for the allocated costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1).

Administrative Services Agreement

We and our General Partner, Enterprise Products Partners and its general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner and certain affiliated entities are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO provides administrative, management and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.
- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses (direct and indirect) incurred by EPCO which are directly or indirectly related to our business or activities (including EPCO expenses reasonably allocated to us). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.
- EPCO allows us to participate as named insureds in its overall insurance program with the associated costs being allocated to us.

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Our operating costs and expenses for the years ended December 31, 2007, 2006 and 2005 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for the years ended December 31, 2007, 2006 and 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

EPCO and its affiliates have no obligation to present business opportunities to us or our Operating Companies, and we and our Operating Companies have no obligation to present business opportunities to EPCO and its affiliates. However, the ASA requires that business opportunities offered to or discovered by EPCO be offered first to certain Enterprise Products Partners' affiliates before they may be pursued by EPCO and its other affiliates or offered to us.

On February 28, 2007, due to the substantial completion of inquires by the FTC into EPCO's acquisition of our General Partner, the parties to the ASA amended it to remove Exhibit B thereto, which had been adopted to address matters the parties anticipated the FTC may consider in its inquiry. Exhibit B had set forth certain separateness and screening policies and procedures among the parties that became inapposite upon the issuance of the FTC's order in connection with the inquiry or were already otherwise reflected in applicable FTC, SEC, NYSE or other laws, standards or governmental regulations.

Sale of Pioneer Plant

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners for $38.0 million in cash. The Pioneer plant was not an integral part of our Midstream Segment operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and recommended for approval by our ACG Committee and a fairness opinion was rendered by an investment banking firm. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

Jonah Joint Venture

On August 1, 2006, Enterprise Products Partners (through an affiliate) became our joint venture partner by acquiring an interest in Jonah, the partnership through which we have owned our interest in the Jonah system. Through December 31, 2007, we have reimbursed Enterprise Products Partners $261.6 million ($152.2 million in 2007 and $109.4 million in 2006) for our share of the Phase V cost incurred by it (including its cost of capital incurred prior to the formation of the joint venture of $1.3 million). At December 31, 2007 and 2006, we had payables to Enterprise Products Partners for costs incurred of $9.9 million and $8.7 million, respectively (see Note 9). At December 31, 2007 and 2006, we had receivables from Jonah of $6.0 million and $11.5 million, respectively, for distributions and operating expenses.

We have agreed to indemnify Enterprise Products Partners from any and all losses, claims, demands, suits, liability, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the formation of the Jonah joint venture, Jonah's ownership or operation of the Jonah system prior to the effective date of the joint venture, and any environmental activity, or violation of or liability under environmental laws arising from or related to the condition of the Jonah system prior to the effective date of the joint venture. In general, a claim for indemnification cannot be filed until the losses suffered by Enterprise Products Partners exceed $1.0 million, and the maximum potential amount of future payments under the indemnity is limited to $100.0 million. However, if certain representations or warranties are breached, the maximum potential amount of future payments under the indemnity is capped at $207.6 million. All indemnity payments are net of insurance recoveries that Enterprise Products Partners may receive from third-party insurers. We carry insurance coverage that may offset any payments required under the indemnity. We do not expect that these indemnities will have a material adverse effect on our financial position, results of operations or cash flows.

Sale of General Partner to Enterprise GP Holdings; Relationship with Energy Transfer Equity

On May 7, 2007, all of the membership interests in our General Partner, together with 4,400,000 of our Units, were sold by DFIGP to Enterprise GP Holdings, a publicly traded partnership also controlled indirectly by Dan L. Duncan. As of May 7, 2007, Enterprise GP Holdings owns and controls the 2% general partner interest in us and has the right (through its 100% ownership of our General Partner) to receive the incentive distribution rights associated with the general partner interest. Enterprise GP Holdings, DFIGP and other entities controlled by Mr. Duncan own 16,691,550 of our Units.

Concurrently with the acquisition of our General Partner, Enterprise GP Holdings acquired non-controlling ownership interests in Energy Transfer Equity, L.P. ("Energy Transfer Equity") and LE GP, LLC ("ETE GP"), the general partner of Energy Transfer Equity. Following the transaction, Enterprise GP Holdings owns approximately 34.9% of the membership interests in ETE GP and 38,976,090 common units of Energy Transfer Equity representing approximately 17.6% of the outstanding limited partner interests in Energy Transfer Equity.

Other Transactions

On October 6, 2006, we sold certain crude oil pipeline assets and refined products pipeline assets in the Houston, Texas area, to a subsidiary of Enterprise Products Partners for approximately $11.7 million. These assets, which had been idle since acquisition, were part of the assets acquired by us in 2005. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of these pipeline assets at September 30, 2006, was approximately $6.0 million. We recognized a gain of $5.7 million on this transaction (see Note 10).

In November 2006, we entered into a lease with Duncan Energy Partners, for a 12-mile, 10-inch interconnecting pipeline extending from Pasadena, Texas to Baytown, Texas. The primary term of this lease expired on September 15, 2007, and we have continued on a month-to-month basis subject to termination by either party upon 60 days' notice.

In December 2006, we constructed a new 20-inch diameter lateral pipeline to connect our Downstream Segment mainline system to the Enterprise Products Partners facilities at Mont Belvieu, Texas, at a cost of approximately $8.6 million. The new connection, which provides delivery of propane from Enterprise Products Partners into our system at full line flow rates, complements our current ability to source product from Mont Belvieu. The new connection also offers the ability to deliver other liquid products such as butanes and natural gasoline from Enterprise Products Partners' storage facilities into our system at reduced flow rates until enhancements can be made. This new pipeline replaces a 10-mile, 18-inch segment of pipeline that we sold to an Enterprise Products Partners' affiliate on January 23, 2007 for approximately $8.0 million. These assets had a net book value of approximately $2.5 million, and we recognized a gain on the sale of approximately $5.5 million (see Note 10). The sales proceeds were used to fund construction of the replacement pipeline.

In June 2007, we purchased 300,000 barrels of propane linefill from an affiliate of Enterprise Products Partners for approximately $14.4 million. In November 2007, we purchased 100,000 barrels of butane inventory from an affiliate of Enterprise Products Partners for approximately $8.0 million.

Relationship with Unconsolidated Affiliates

Our significant related party revenues and expense transactions with unconsolidated affiliates consist of management, rental and other revenues, transportation expense related to movements on Centennial and Seaway and rental expense related to the lease of pipeline capacity on Centennial. For additional information regarding our unconsolidated affiliates, see Note 9.

NOTE 16. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income or loss allocated to limited partner interests by the weighted average number of distribution-bearing Units outstanding during a period. The amount of net income allocated to limited partner interests is derived by subtracting our General Partner’s share of the net income from net income. Diluted earnings per Unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing Units outstanding during a period (as used in determining basic earnings per Unit); and (ii) the number of incremental Units resulting from the assumed exercise of dilutive unit options outstanding during a period (the “incremental option units”).

In a period of net operating losses, restricted units and incremental option units are excluded from the calculation of diluted earnings per Unit due to their anti-dilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase Units at an average market value during the period. The amount of Units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

In May 2007, we granted 155,000 unit options to employees providing services to us (see Note 4). These unit options were excluded from the computation of diluted earnings per Unit due to their anti-dilutive effect as they represent unit options with an exercise price greater than the average market price of a Unit for the period.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table shows the computation of basic and diluted earnings per Unit for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31, 2007	2006	2005
Income from continuing operations	$ 279,180	$ 182,682	$ 159,401
Discontinued operations	—	19,369	3,150
Net income	279,180	202,051	162,551
General Partner's interest in net income	16.47%	28.57%	29.27%
Earnings allocated to General Partner:			
Income from continuing operations	$ 45,987	$ 52,199	$ 46,657
Discontinued operations	—	5,534	922
Net income allocated	45,987	57,733	47,579
BASIC EARNINGS PER UNIT:			
Numerator:			
Income from continuing operations	$ 233,193	$ 130,483	$ 112,744
Discontinued operations	—	13,835	2,228
Limited partners' interest in net income	$ 233,193	$ 144,318	$ 114,972
Denominator:			
Units	89,812	73,657	67,397
Time-vested restricted Units	38	—	—
Total Weighted average Units outstanding	89,850	73,657	67,397
Basic earnings per Unit:			
Income from continuing operations	$ 2.60	$ 1.77	$ 1.67
Discontinued operations	—	0.19	0.04
Limited partners' interest in net income	$ 2.60	$ 1.96	$ 1.71
DILUTED EARNINGS PER UNIT:			
Numerator:			
Income from continuing operations	$ 233,193	$ 130,483	$ 112,744
Discontinued operations	—	13,835	2,228
Limited partners' interest in net income	$ 233,193	$ 144,318	$ 114,972
Denominator:			
Units	89,812	73,657	67,397
Time-vested restricted Units	38	—	—
Total Weighted average Units outstanding	89,850	73,657	67,397
Diluted earnings per Unit:			
Income from continuing operations	$ 2.60	$ 1.77	$ 1.67
Discontinued operations	—	0.19	0.04
Limited partners' interest in net income	$ 2.60	$ 1.96	$ 1.71

Our General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our Partnership Agreement. On December 8, 2006, our Partnership Agreement was amended (see Note 1), and our General Partner's maximum percentage interest in our quarterly distributions was reduced from 50% to 25%. We issued 14.1 million Units on December 8, 2006 to our General Partner as consideration for the IDR Reduction Amendment. The number of Units issued to our General Partner was based upon a predetermined formula that, based on the distribution rate and the number of Units outstanding at the time of the issuance, resulted in our General Partner receiving cash distributions from the newly-issued Units and from its reduced maximum percentage interest in our quarterly distributions approximately equal to the cash distributions our General Partner would have received from its maximum percentage interest in our quarterly distributions without the IDR Reduction Amendment. At December 31, 2007, 2006 and 2005, we had outstanding 89,911,532, 89,804,829 and 69,963,554 Units, respectively.

NOTE 17. COMMITMENTS AND CONTINGENCIES

Litigation

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs assert damages attributable to the remediation of the property of approximately $1.4 million. This case has been stayed pending the completion of remediation pursuant to the Louisiana Department of Environmental Quality ("LDEQ") requirements. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of our other unitholders, and derivatively on our behalf, concerning proposals made to our unitholders in our definitive proxy statement filed with the SEC on September 11, 2006 ("Proxy Statement") and other transactions involving us and Enterprise Products Partners or its affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants the General Partner; the Board of Directors of the General Partner; EPCO; Enterprise Products Partners and certain of its affiliates and Dan L. Duncan. We are named as a nominal defendant.

The amended complaint alleges, among other things, that certain of the transactions adopted at a special meeting of our unitholders on December 8, 2006, including a reduction of the General Partner's maximum percentage interest in our distributions in exchange for Units (the "Issuance Proposal"), were unfair to our unitholders and constituted a breach by the defendants of fiduciary duties owed to our unitholders and that the Proxy Statement failed to provide our unitholders with all material facts necessary for them to make an informed decision whether to vote in favor of or against the proposals. The amended complaint further alleges that, since Mr. Duncan acquired control of the General Partner in 2005, the defendants, in breach of their fiduciary duties to us and our unitholders, have caused us to enter into certain transactions with Enterprise Products Partners or its affiliates that were unfair to us or otherwise unfairly favored Enterprise Products Partners or its affiliates over us. The amended complaint alleges that such transactions include the Jonah joint venture entered into by us and an Enterprise Products Partners affiliate in August 2006 (citing the fact that our ACG Committee did not obtain a fairness opinion from an independent investment banking firm in approving the transaction), and the sale by us to an Enterprise Products Partners' affiliate of the Pioneer plant in March 2006. As more fully described in the Proxy Statement, the ACG Committee recommended the Issuance Proposal for approval by the Board of Directors of the General Partner. The amended complaint also alleges that Richard S. Snell, Michael B. Bracy and Murray H. Hutchison, constituting the three members of the ACG Committee, cannot be considered independent because of their alleged ownership of securities in Enterprise Products Partners and its affiliates and/or their relationships with Mr. Duncan.

The amended complaint seeks relief (i) awarding damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the complaint; (ii) rescinding all actions taken pursuant to the Proxy vote and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts.

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

Regulatory Matters

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

We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations, and that the cost of compliance with such laws and regulations will not have a material adverse effect on our results of operations or financial position. We cannot ensure, however, that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. At December 31, 2007 and 2006, we have accrued liabilities of $4.0 million and $1.8 million, respectively, related to sites requiring environmental remediation activities.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In 1999, our Arcadia, Louisiana, facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of environmental contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At December 31, 2007, we have an accrued liability of $0.6 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the U.S. Department of Justice (“DOJ”) of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, was seeking a civil penalty against us for alleged violations of the Clean Water Act arising out of this release, as well as three smaller spills at other locations in 2004 and 2005. We agreed with the DOJ on a penalty of approximately $2.9 million, along with our commitment to implement additional spill prevention measures. In August 2007, we deposited $2.9 million into a restricted cash account per the terms of the settlement, and in October 2007, we paid the $2.9 million plus interest earned on the amount to the DOJ. This settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

One of the spills encompassed in our current settlement discussion with the DOJ involved a 37,450-gallon release from Seaway on May 13, 2005 at Colbert, Oklahoma. This release was remediated under the supervision of the Oklahoma Corporation Commission, but resulted in claims by neighboring landowners that have been settled for approximately $1.0 million. In addition, the release resulted in a Corrective Action Order by the U.S. Department of Transportation. Among other requirements of this Order, we were required to reduce the operating pressure of Seaway by 20% until completion of required corrective actions. The corrective actions were completed and on June 1, 2006, we increased the operating pressure of Seaway back to 100%. We have a 50% ownership interest in Seaway, and our share of the settlement was covered by our insurance. The settlement of the Colbert release did not have a material adverse effect on our financial position, results of operations or cash flows.

We are also in negotiations with the U.S. Department of Transportation with respect to a notice of probable violation that we received on April 25, 2005, for alleged violations of pipeline safety regulations at our Todhunter facility, with a proposed $0.4 million civil penalty. We responded on June 30, 2005, by admitting certain of the alleged violations, contesting others and requesting a reduction in the proposed civil penalty. We do not expect any settlement, fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows.

The FERC, pursuant to the Interstate Commerce Act of 1887, as amended, the Energy Policy Act of 1992 and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under that Act, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest, and the FERC may investigate, the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected with interest pursuant to rates that are ultimately found to be unlawful. The FERC and interested parties can also challenge tariff rates that have become final and effective. Because of the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of our rates could adversely affect our revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. Our interstate tariff rates are either market-based or derived in accordance with the FERC’s indexing methodology, which currently allows a pipeline to increase its rates by a percentage linked to the producer price index for finished goods. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC’s approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

Although our natural gas gathering systems are generally exempt from FERC regulation under the Natural Gas Act of 1938, FERC regulation still significantly affects our natural gas gathering business. In recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue this approach, it could have an adverse effect on the rates we are able to charge in the future. In addition, our natural gas gathering operations could be adversely affected in the future should they become subject to the application of federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered and adopted from time to time. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2007. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
	Total	2008	2009	2010	2011	2012	Thereafter
Maturities of long-term debt (1) (2)	$1,845,000	$355,000	$ —	$ —	$ —	$990,000	$ 500,000
Interest payments (3)	$1,633,447	$105,634	$ 99,354	$ 99,354	$ 99,354	$ 79,126	$1,150,625
Operating leases (4)	$ 64,915	$ 13,397	$ 11,543	$ 9,883	$ 8,899	$ 8,227	$ 12,966
Purchase obligations (5):							
Product purchase commitments:							
Estimated payment obligation:							
Crude oil	$ 387,210	$387,210	$ —	$ —	$ —	$ —	$ —
Other	$ 3,971	$ 2,199	$ 871	$ 325	$ 291	$ 267	$ 18
Underlying major volume commitments:							
Crude oil (in barrels)	4,492	4,492	—	—	—	—	—
Service payment commitments	$ 8,974	$ 4,499	$ 4,131	$ 344	$ —	$ —	$ —
Capital expenditure obligations (6)	$ 11,335	$ 11,335	$ —	$ —	$ —	$ —	$ —
Other liabilities and deferred credits (7)	$ 27,122	$ —	$ 2,418	$ 2,417	$ 2,367	$ 1,892	$ 18,028

(1) We have long-term payment obligations under our Revolving Credit Facility, our Senior Notes and our Junior Subordinated Notes. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated (see Note 12 for additional information regarding our consolidated debt obligations).

(2) On January 28, 2008, TE Products redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. The 6.45% TE Products Senior Notes matured on January 15, 2008. Retirement of these series of notes was funded with borrowings under our Term Credit Agreement (see Note 22).

(3) Includes interest payments due on our Senior Notes and junior subordinated notes and interest payments and commitment fees due on our Revolving Credit Facility. The interest amount calculated on the Revolving Credit Facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(4) We lease property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year for the periods indicated. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. Total rental expense for the years ended December 31, 2007, 2006 and 2005, was $22.1 million, $25.3 million and $24.0 million, respectively.

(5) We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The preceding table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at December 31, 2007. The majority of contractual commitments we make for the purchase of crude oil range in term from a thirty-day evergreen to one year. A substantial portion of the contracts for the purchase of crude oil that extend beyond thirty days include cancellation provisions that allow us to cancel the contract with thirty days written notice.

(6) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services rendered or products purchased.

(7) Includes approximately $10.1 million of long-term deferred revenue payments, which are being transferred to income over the term of the respective revenue contracts and $12.8 million related to our estimated long-term portions of our liabilities under our guarantees to Centennial for its credit agreement and for a catastrophic event. The amount of commitment by year is our best estimate of projected payments of these long-term liabilities.

Other

At December 31, 2007 and 2006, Centennial's debt obligations consisted of $140.0 million borrowed under a master shelf loan agreement, and $150.0 million ($140.0 million borrowed under a master shelf loan agreement and $10.0 million borrowed under an additional credit agreement, which terminated in April 2007), respectively. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under this credit facility. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $70.0 million each at December 31, 2007. Provisions included in the Centennial credit facility required that certain financial metrics be achieved and for the guarantees to be removed by May 2007. These metrics were not achieved, and the Centennial credit facility was amended in May 2007 to require the guarantees to remain throughout the life of the debt. As a result of the guarantee, at December 31, 2007, TE Products has a liability of $9.5 million, which represents the present value of the estimated amount, based on a probability estimate, we would have to pay under the guarantee.

TE Products, Marathon and Centennial have also entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, at December 31, 2007, TE Products has a liability of $4.1 million, which represents the present value of the estimated amount, based on a probability estimate, we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, such contributions might be covered by our insurance (net of deductible), depending upon the nature of the catastrophic event.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various equipment. Lease expense related to this equipment is approximately $5.2 million per year. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees. We do not believe that any performance under the guarantee would have a material effect on our financial condition, results of operations or cash flows.

On February 24, 2005, the General Partner was acquired from DCP by DFIGP. The General Partner owns a 2% general partner interest in us and is our general partner. On March 11, 2005, the Bureau of Competition of the FTC delivered written notice to DFIGP's legal advisor that it was conducting a non-public investigation to determine whether DFIGP's acquisition of our General Partner may substantially lessen competition or violate other provisions of federal antitrust laws. We and our General Partner cooperated fully with this investigation.

On October 31, 2006, an FTC order and consent agreement ending its investigation became final. The order required the divestiture of our equity interest in MB Storage, its general partner and certain related assets to one or more FTC-approved buyers in a manner approved by the FTC and subject to its final approval. The order contained no minimum price for the divestiture and required that we provide the acquirer or acquirers the opportunity to hire employees who spend more than 10% of their time working on the divested assets. The order also imposed specified operational, reporting and consent requirements on us including, among other things, in the event that we acquire interests in or operate salt dome storage facilities for NGLs in specified areas. The FTC approved a buyer and sale terms for our equity interests and certain related assets, and we closed on such sale on March 1, 2007 (see Note 10).

In December 2006, we signed an agreement with Motiva Enterprises, LLC ("Motiva") for us to construct and operate a new refined products storage facility to support the expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we are constructing a 5.4 million barrel refined products storage facility for gasoline and distillates. The agreement also provides for a 15-year throughput and dedication of volume, which will commence upon completion of the refinery expansion. The project includes the construction of 20 storage tanks, five 5.4-mile product pipelines connecting the storage facility to Motiva's refinery, 21,000 horsepower of pumping capacity, and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. The storage and pipeline project is expected to be completed by January 1, 2010. As a part of a separate but complementary initiative, we are constructing an 11-mile, 20-inch pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas, which is the primary origination facility for our mainline system. These projects will facilitate connections to additional markets through the Colonial, Explorer and Magtex pipeline systems and provide the Motiva refinery with access to our pipeline system. The total cost of the project is expected to be approximately $310.0 million, which includes $20.0 million for the 11-mile, 20-inch pipeline, $30.0 million of capitalized interest and $17.0 million of scope changes requested by Motiva. Through December 31, 2007, we have spent approximately $47.0 million on this construction project. Under the terms of the agreement, if Motiva cancels the agreement prior to the commencement date of the project, Motiva will reimburse us the actual reasonable expenses we have incurred after the effective date of the agreement, including both internal and external costs that would be capitalized as a part of the project, plus a ten percent cancellation fee.

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2007, TCTM and TE Products had approximately 3.1 million barrels and 10.3 million barrels, respectively, of products in their custody that were owned by customers. We are obligated for the transportation, storage and delivery of such products on behalf of our customers. We maintain insurance adequate to cover product losses through circumstances beyond our control.

Insurance

We carry insurance coverage we believe to be consistent with the exposures associated with the nature and scope of our operations. As of December 31, 2007, our current insurance coverage includes (1) commercial general liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage, and (4) property insurance covering the replacement value of all real and personal property damage, including damages arising from earthquake, flood damage and business interruption/extra expense. For select assets, we also carry pollution liability insurance that provides coverage for historical and gradual pollution events. All coverages are subject to certain deductibles, limits or sub-limits and policy terms and conditions.

We also maintain excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are commensurate with the nature and scope of our operations. The cost of our general insurance coverages has increased over the past year reflecting the changing conditions of the insurance markets. These insurance policies, except for the pollution liability policies, are through EPCO (see Note 15).

Commitments under our EPCO equity compensation plan

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 1). This includes costs associated with unit option awards granted to these employees to purchase our Units. At December 31, 2007, there were 155,000 unit options outstanding for which we were responsible for reimbursing EPCO for the costs of such awards (see Note 4).

The weighted-average strike price of unit option awards outstanding at December 31, 2007 was $45.35 per Unit. At December 31, 2007, none of these unit options were exercisable. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 4 for additional information regarding our accounting for unit-based awards.

NOTE 18. CONCENTRATIONS OF CREDIT RISK

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

For the years ended December 31, 2007, 2006 and 2005, Valero Energy Corp. accounted for 16%, 14% and 14%, respectively, of our total consolidated revenues, and for the years ended December 31, 2007 and 2006, BP Oil Supply Company accounted for 14% and 11%, respectively, of our total consolidated revenues. Additionally, for the year ended December 31, 2007, Shell Trading Company accounted for 12% of our total consolidated revenues. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2007, 2006 and 2005.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 19. SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities, (ii) non-cash investing activities and (iii) cash payments for interest for the years ended December 31, 2007, 2006 and 2005:

	For Year Ended December 31,		
	2007	2006	2005
Decrease (increase) in:			
Accounts receivable, trade	$(529,055)	$ (67,317)	$(249,745)
Accounts receivable, related parties	(5,986)	1,736	6,638
Inventories	(8,255)	(45,002)	(970)
Other current assets	(7,356)	25,552	(19,088)
Other	(27,244)	(9,906)	(4,371)
Increase (decrease) in:			
Accounts payable and accrued expenses	558,111	44,348	254,251
Accounts payable, related parties	3,374	15,696	(12,817)
Other	3,766	(6,135)	(11,252)
Net effect of changes in operating accounts	$ (12,645)	$ (41,028)	$ (37,354)
Non-cash investing activities:			
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ —	$ —	$ 1,429
Net assets transferred to Jonah Gas Gathering Company	$ —	$ 572,609	$ —
Payable to Enterprise Gas Processing, LLC for spending for Phase V expansion of Jonah Gas Gathering Company	$ 9,878	$ 8,732	$ —
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 104,220	$ 88,107	$ 82,315

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NOTE 20. SELECTED QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2007:				
Operating revenues	$ 1,978,429	$ 2,049,436	$ 2,580,657	$ 3,049,538
Operating income	83,434	50,729	54,719	60,673
Net income	138,191	47,760	47,631	45,598
Basic and diluted net income per Limited Partner Unit (1) (2)	$ 1.29	$ 0.44	$ 0.44	$ 0.42

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2006:				
Operating revenues	$ 2,536,369	$ 2,425,052	$ 2,570,045	$ 2,076,019
Operating income	62,638	58,170	51,839	57,132
Income from continuing operations	43,383	41,586	41,145	56,568
Income from discontinued operations	19,491	(122)	—	—
Net income	62,874	41,464	41,145	56,568
Basic and diluted net income per Limited Partner Unit: (1)				
Continuing operations	$ 0.43	$ 0.42	$ 0.39	$ 0.53
Discontinued operations	0.19	—	—	—
Basic and diluted net income per Limited Partner Unit	$ 0.62	$ 0.42	$ 0.39	$ 0.53

(1) Per Unit calculations include 106,703 Units issued in 2007 (62,400 restricted units, 4,507 Units issued under the employee unit purchase plan and 39,796 Units issued under the DRIP), 14,091,275 Units issued in December 2006 to our General Partner and 5,750,000 Units issued in July 2006 in an underwritten public offering.

(2) The sum of the four quarters does not equal the total year due to rounding.

NOTE 21. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

TE Products, TCTM, TEPPCO Midstream and Val Verde have issued full, unconditional, and joint and several guarantees of our Senior Notes, our Junior Subordinated Notes (collectively “the Guaranteed Debt”), our Revolving Credit Facility and our Term Credit Facility. In addition, during the 2006 period presented below and extending through July 31, 2006, Jonah also had provided the same guarantees of our Senior Notes. Effective August 1, 2006, Enterprise Products Partners, through its affiliate, Enterprise Gas Processing, LLC, became our joint venture partner by acquiring an interest in Jonah (see Note 9). Jonah was released as a guarantor of the Senior Notes and Revolving Credit Facility, effective upon the formation of the joint venture. For periods prior to January 1, 2006, TE Products, TCTM, TEPPCO Midstream, Jonah and Val Verde are collectively referred to as the “Guarantor Subsidiaries” and for periods after January 1, 2006, references to “Guarantor Subsidiaries” exclude Jonah.

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

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

	December 31, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 32,302	$ 77,083	$ 1,499,653	$ (93,049)	$ 1,515,989
Property, plant and equipment — net	—	1,142,630	651,004	—	1,793,634
Equity investments	1,286,021	1,347,313	188,669	(1,675,008)	1,146,995
Intercompany notes receivable	1,511,168	—	—	(1,511,168)	—
Intangible assets	—	136,050	28,631	—	164,681
Other assets	8,580	34,839	85,401	(62)	128,758
Total assets	$ 2,838,071	$ 2,737,915	$ 2,453,358	$ (3,279,287)	$ 4,750,057
Liabilities and partners' capital					
Current liabilities	$ 61,926	$ 493,184	$ 1,485,164	$ (93,049)	$ 1,947,225
Long-term debt	1,511,083	—	—	—	1,511,083
Intercompany notes payable	—	1,006,801	504,367	(1,511,168)	—
Other long term liabilities	435	24,466	2,283	(62)	27,122
Total partners' capital	1,264,627	1,213,464	461,544	(1,675,008)	1,264,627
Total liabilities and partners' capital	$ 2,838,071	$ 2,737,915	$ 2,453,358	$ (3,279,287)	$ 4,750,057

	December 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 37,534	$ 149,056	$ 894,916	$ (114,796)	$ 966,710
Property, plant and equipment — net	—	958,266	683,829	—	1,642,095
Equity investments	1,320,672	1,317,671	195,606	(1,794,239)	1,039,710
Intercompany notes receivable	1,215,132	—	—	(1,215,132)	—
Intangible assets	—	153,803	31,607	—	185,410
Other assets	5,769	21,657	60,741	—	88,167
Total assets	$ 2,579,107	$ 2,600,453	$ 1,866,699	$ (3,124,167)	$ 3,922,092
Liabilities and partners' capital					
Current liabilities	$ 40,578	$ 161,101	$ 889,665	$ (114,796)	$ 976,548
Long-term debt	1,215,948	387,339	—	—	1,603,287
Intercompany notes payable	—	711,381	503,751	(1,215,132)	—
Other long term liabilities	2,251	17,857	1,819	—	21,927
Total partners' capital	1,320,330	1,322,775	471,464	(1,794,239)	1,320,330
Total liabilities and partners' capital	$ 2,579,107	$ 2,600,453	$ 1,866,699	$ (3,124,167)	$ 3,922,092

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For Year Ended December 31, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 385,902	$ 9,272,707	$ (549)	$ 9,658,060
Costs and expenses	—	278,630	9,153,588	(5,060)	9,427,158
Gains on sales of assets	—	(18,653)	—	—	(18,653)
Operating income	—	125,925	119,119	4,511	249,555
Interest expense — net	—	(72,705)	(28,518)	—	(101,223)
Gain on sale of ownership interest in MB Storage	—	59,628	—	—	59,628
Equity earnings	279,180	164,107	2,602	(377,134)	68,755
Other income — net	—	2,255	767	—	3,022
Income before provision for income taxes	279,180	279,210	93,970	(372,623)	279,737
Provision for income taxes	—	30	527	—	557
Net income	$ 279,180	$ 279,180	$ 93,443	$ (372,623)	$ 279,180

	For Year Ended December 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 352,844	$ 9,263,451	$ (8,810)	$ 9,607,485
Costs and expenses	—	278,973	9,117,359	(11,222)	9,385,110
Gains on sales of assets	—	(1,415)	(5,989)	—	(7,404)
Operating income	—	75,286	152,081	2,412	229,779
Interest expense — net	—	(52,980)	(33,191)	—	(86,171)
Equity earnings	202,051	178,335	11,896	(355,521)	36,761
Other income — net	—	1,545	1,420	—	2,965
Income before provision for income taxes	202,051	202,186	132,206	(353,109)	183,334
Provision for income taxes	—	135	517	—	652
Income from continuing operations	202,051	202,051	131,689	(353,109)	182,682
Discontinued operations	—	—	19,369	—	19,369
Net income	$ 202,051	$ 202,051	$ 151,058	$ (353,109)	$ 202,051

	For Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ —	$ 439,944	$ 8,168,657	$ (3,567)	$ 8,605,034
Costs and expenses	—	285,072	8,104,164	(3,567)	8,385,669
Gains on sales of assets	—	(551)	(117)	—	(668)
Operating income	—	155,423	64,610	—	220,033
Interest expense — net	—	(54,011)	(27,850)	—	(81,861)
Equity earnings	162,551	57,088	23,078	(222,623)	20,094
Other income — net	—	901	234	—	1,135
Income from continuing operations	162,551	159,401	60,072	(222,623)	159,401
Discontinued operations	—	3,150	—	—	3,150
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For Year Ended December 31, 2007				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating activities					
Net income	$ 279,180	$ 279,180	$ 93,443	$ (372,623)	$ 279,180
Adjustments to reconcile net income to net cash from operating activities:					
Deferred income taxes	—	(687)	8	—	(679)
Depreciation and amortization	—	75,377	29,848	—	105,225
Earnings in equity investments, net of distributions	15,270	33,217	9,798	(4,140)	54,145
Gains on sales of assets and ownership interest	—	(78,281)	—	—	(78,281)
Changes in assets and liabilities and other	(299,736)	(61,634)	56,222	296,130	(9,018)
Net cash from operating activities	(5,286)	247,172	189,319	(80,633)	350,572
Cash flows from investing activities	—	(212,791)	(104,609)	—	(317,400)
Cash flows from financing activities	2,458	(34,311)	(84,758)	83,392	(33,219)
Net change in cash and cash equivalents	(2,828)	70	(48)	2,759	(47)
Cash and cash equivalents, January 1	10,975	—	70	(10,975)	70
Cash and cash equivalents, December 31	$ 8,147	$ 70	$ 22	$ (8,216)	$ 23

	For Year Ended December 31, 2006				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating activities					
Net income	$ 202,051	$ 202,051	$ 151,058	$ (353,109)	$ 202,051
Adjustments to reconcile net income to net cash from continuing operating activities:					
Income from discontinued operations	—	—	(19,369)	—	(19,369)
Deferred income taxes	—	135	517	—	652
Depreciation and amortization	—	71,100	37,152	—	108,252
Earnings in equity investments, net of distributions	76,515	36,636	8,613	(95,042)	26,722
Gains on sales of assets	—	(5,599)	(1,805)	—	(7,404)
Changes in assets and liabilities and other	(75,103)	(47,167)	(28,143)	111,061	(39,352)
Net cash from continuing operating activities	203,463	257,156	148,023	(337,090)	271,552
Cash flows from discontinued operations	—	—	1,521	—	1,521
Net cash from operating activities	203,463	257,156	149,544	(337,090)	273,073
Cash flows from investing activities	(195,060)	48,236	(80,645)	(46,247)	(273,716)
Cash flows from financing activities	594	(305,392)	(68,936)	374,328	594
Net change in cash and cash equivalents	8,997	—	(37)	(9,009)	(49)
Cash and cash equivalents, January 1	1,978	—	107	(1,966)	119
Cash and cash equivalents, December 31	$ 10,975	$ —	$ 70	$ (10,975)	$ 70

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating activities					
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551
Adjustments to reconcile net income to net cash from continuing operating activities:					
Income from discontinued operations	—	(3,150)	—	—	(3,150)
Depreciation and amortization	—	82,536	28,193	—	110,729
Earnings in equity investments, net of distributions	88,550	14,598	1,576	(87,733)	16,991
Gains on sales of assets	—	(551)	(117)	—	(668)
Changes in assets and liabilities and other	(54,540)	(57,645)	22,884	53,571	(35,730)
Net cash from continuing operating activities	196,561	198,339	112,608	(256,785)	250,723
Cash flows from discontinued operations	—	3,782	—	—	3,782
Net cash from operating activities	196,561	202,121	112,608	(256,785)	254,505
Cash flows from investing activities	(278,806)	(31,529)	(180,486)	139,906	(350,915)
Cash flows from financing activities	80,107	(184,126)	65,097	119,029	80,107
Net change in cash and cash equivalents	(2,138)	(13,534)	(2,781)	2,150	(16,303)
Cash and cash equivalents, January 1	4,116	13,596	2,826	(4,116)	16,422
Cash and cash equivalents, December 31	$ 1,978	$ 62	$ 45	$ (1,966)	$ 119

NOTE 22. SUBSEQUENT EVENTS

Debt Obligations and Treasury Locks

On January 15, 2008, the 6.45% TE Products Senior Notes matured. On January 28, 2008, TE Products redeemed the remaining $175.0 million of 7.51% TE Products Senior Notes at a redemption price of 103.755% of the principal amount plus accrued and unpaid interest at the date of redemption. The $180.0 million principal amount of 6.45% TE Products Senior Notes and the $175.0 million principal amount of 7.51% TE Products Senior Notes were repaid with borrowings under our Term Credit Agreement. The remaining loss on the termination of an interest rate swap that had been deferred as an adjustment to the carrying value of the 7.51% TE Products Senior Notes and was being amortized using the effective interest method as an increase to future interest expense over the remaining term of the 7.51% TE Products Senior Notes (see Note 6) was recognized at the time of extinguishment of the Senior Notes in January 2008.

In January 2008, we extended the expiration date to April 30, 2008 of $600.0 million notional amount of treasury lock agreements that were set to expire on January 31, 2008. The weighted average rate under the treasury lock agreements is approximately 4.50%.

Centennial Guaranty

In January 2008, we entered into an amended and restated guaranty agreement (“Amended Guaranty”) in which we, TCTM, TEPPCO Midstream and TE Products (collectively, “TEPPCO Guarantors”) are required, on a joint and several basis, to pay 50% of any amount under Centennial’s master shelf loan agreement that Centennial does not pay when due. The Amended Guaranty also has a credit maintenance requirement whereby we may be required to provide additional credit support or pay certain fees if our credit ratings fall below levels specified in the Amended Guaranty.

Chaparral Open Season

In February 2008, our subsidiary, Chaparral, announced the start of a binding “open season” process to seek shipper support for a proposed expansion of its 845-mile NGL pipeline originating in the Permian Basin of West Texas and eastern New Mexico. The open season is being held to obtain commitments from shippers for a 15-year term at a transportation rate that is sufficient to justify the capital expenditures necessary to expand the Chaparral pipeline capacity. The Chaparral pipeline delivers NGLs to the NGL fractionation complex in Mont Belvieu, Texas. The expansion project is designed to increase annual average system capacity by approximately 15,000 barrels per day or 20,000 barrels per day, depending on shipper response to the open season. The expansion would involve upgrading certain pipe sections, and may include installing additional pumping capability at existing pump stations. If there is sufficient shipper commitment, the additional capacity could be available as soon as early 2009. The open season began February 11, 2008 and continues until March 27, 2008. By April 30, 2008, Chaparral expects to notify shippers who have submitted an executed transportation services agreement whether or not the expansion project will proceed. By signing the transportation services agreement, the shipper will also agree to support Chaparral in any regulatory filings associated with the implementation of the concomitant services.

Acquisition

On February 1, 2008, we, through our TEPPCO Marine Services, LLC subsidiary ("TEPPCO Marine"), entered the marine transportation business for refined products, crude oil and lubrication products. We acquired transportation assets and certain intangible assets that comprised the marine transportation business of Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr., the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. (collectively, "Cenac"). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the "Marine Transportation Business") was $443.8 million, which consisted of $256.6 million in cash and 4,854,899 newly issued Units. Additionally, we assumed $63.2 million of Cenac's long-term debt in this transaction.

Cash payment for Marine Transportation Business	$ 256,593
Fair value of our 4,854,899 Units	186,558
Other cash acquisition costs paid to third-parties	672
Total consideration	$ 443,823

We financed the cash portion of the total consideration with borrowings under our Term Credit Agreement (see Note 12). In accordance with purchase accounting, the value of our Units issued in connection with the Marine Transportation Business was based on the average closing price of such Units immediately prior to and on the day of February 1, 2008. For the purpose of this calculation, the average closing price was $38.43 per Unit.

We acquired 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements. This business serves refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, as well as the Intracoastal Waterway between Texas and Florida. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast and in the Gulf of Mexico. This acquisition is a natural extension of our existing assets and complements two of our core franchise businesses: the transportation and storage of refined products and the gathering, transportation and storage of crude oil.

The results of operations for our Marine Transportation Business will be included in our consolidated financial statements at the date of acquisition. Our fleet of acquired push boats and barges will continue to be operated by employees of Cenac under a transitional operating agreement with TEPPCO Marine for a period of up to two years following the acquisition. These operations will remain headquartered in Houma, Louisiana during such time.

The purchase agreement gives us the right to repurchase the Units in connection with proposed sales thereof by Cenac for 10 years. If Cenac sells Units during a specified 30-day window for a per unit price that is less than the market value of such Units (as determined under the purchase agreement) on February 1, 2008, we are obligated to pay the difference in such values to Cenac. In addition, if we or any of our affiliates sell any of the assets acquired from Cenac prior to June 30, 2018 and recognize certain "built-in gains" for federal income tax purposes that are allocable to Cenac, we have indemnification obligations under the purchase agreement to pay Cenac an amount generally intended to compensate for the incremental level of double taxation imposed on Cenac as a result of the sale. The purchase agreement prohibits Cenac from competing with our Marine Transportation Business for two years or from soliciting employees and service providers of TEPPCO Marine and its affiliates for four years. The purchase agreement contains other customary representations, warranties, covenants and indemnification provisions.

This acquisition was accounted for using the purchase method of accounting and, accordingly, the cost has been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary fair values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocation for this transaction during 2008. The following table summarizes estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

Property, plant and equipment	$ 381,773
Intangible assets	37,148
Total assets acquired	418,921
Long-term debt	(63,157)
Total liabilities assumed	(63,157)
Total assets acquired less liabilities assumed	355,764
Total consideration given	443,823
Goodwill	$ 88,059

The $37.1 million preliminary fair value of acquired intangible assets represents customer relationships and non-compete agreements. Customer relationship intangible assets represent the estimated economic value attributable to certain relationships acquired in connection with the Marine Transportation Business whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. In this context, customer relationships arise from contractual arrangements (such as transportation contracts) and through means other than contracts, such as regular contact by sales or service representative. The values assigned to these intangible assets are amortized to earnings on a straight-line basis over the expected period of economic benefit, which we expect to range from 2 to 20 years.

Of the $443.8 million in consideration we paid or issued to effect acquisition of the Marine Transportation Business, $88.1 million has been assigned to goodwill. Management attributes the value of this goodwill to potential future benefits we expect to realize as a result of acquiring our Marine Transportation Business. Specifically, we expect that an increase in our customer base and expansion of our core businesses will improve earnings on a consolidated basis.

We assumed $63.2 million of long-term debt in connection with our acquisition of the Marine Transportation Business. On February 1, 2008, we repaid the $63.2 million of assumed debt in full with borrowings under our Term Credit Agreement.

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Jonah Gas Gathering Company and Subsidiary

(A Wyoming General Partnership)

Consolidated Financial Statements for the Years Ended
December 31, 2007 and 2006
(With Independent Auditors' Report)

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JONAH GAS GATHERING COMPANY AND SUBSIDIARY

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INDEPENDENT AUDITORS' REPORT

To the Partners of
Jonah Gas Gathering Company:

We have audited the accompanying consolidated balance sheets of Jonah Gas Gathering Company and Subsidiary (the "Partnership") as of December 31, 2007 and 2006, and the related consolidated statements of income, consolidated partners' capital, and consolidated cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 present fairly, in all material respects, the financial position of Jonah Gas Gathering Company and Subsidiary at December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2008

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 11,459	$ —
Accounts receivable, trade	35,236	24,629
Accounts receivable, related parties	845	2,492
Inventories	1,717	1,319
Other	6,139	5,523
Total current assets	55,396	33,963
PROPERTY, PLANT AND EQUIPMENT, NET	910,398	633,459
INTANGIBLE ASSETS	148,784	160,313
GOODWILL	2,776	2,776
OTHER ASSETS	3,346	4,043
Total assets	$ 1,120,700	$ 834,554
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 8,288	$ 6,597
Accounts payable, related parties	6,973	185
Distribution payable	—	11,716
Accrued taxes other than income	1,464	1,160
Other	5,820	5,455
Total current liabilities	22,545	25,113
OTHER LIABILITIES	264	191
Total liabilities	22,809	25,304
COMMITMENTS AND CONTINGENCIES (see Note 10)		
PARTNERS' CAPITAL	1,097,891	809,250
Total liabilities and partners' capital	$ 1,120,700	$ 834,554

See Notes to Consolidated Financial Statements.

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JONAH GAS GATHERING COMPANY AND SUBSIDIARY

STATEMENTS OF CONSOLIDATED INCOME
(Dollars in thousands)

	For Year Ended December 31, 2007	For Year Ended December 31, 2006
REVENUES		
Gathering — Natural gas	$ 135,583	$ 104,415
Sales of natural gas	63,210	50,866
Other revenue	5,353	4,849
Total revenues	204,146	160,130
COSTS AND EXPENSES		
Purchases of natural gas	57,189	48,290
Operating expenses	19,303	12,925
General and administrative expenses	917	242
Depreciation and amortization expense	30,700	19,647
Taxes — other than income taxes	3,825	2,748
Total costs and expenses	111,934	83,852
OPERATING INCOME	92,212	76,278
OTHER INCOME (EXPENSE)		
Interest expense — net	—	(6,812)
Other income	908	198
Total other income (expense)	908	(6,614)
INCOME FROM CONTINUING OPERATIONS	93,120	69,664
DISCONTINUED OPERATIONS		
Income from discontinued operations	—	1,497
Gain on sale of discontinued operations	—	17,872
Total discontinued operations	—	19,369
NET INCOME	$ 93,120	$ 89,033

See Notes to Consolidated Financial Statements.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31, 2007	For Year Ended December 31, 2006
OPERATING ACTIVITIES		
Net income	$ 93,120	$ 89,033
Adjustments to reconcile net income to net cash provided by continuing operating activities:		
Income from discontinued operations	—	(19,369)
Depreciation and amortization	30,700	19,647
Non-cash portion of interest expense	—	174
Net effect of changes in operating accounts	(48)	31,404
Net cash provided by continuing operating activities	123,772	120,889
Net cash provided by discontinued operations	—	1,521
Net cash provided by operating activities	123,772	122,410
INVESTING ACTIVITIES		
Proceeds from the sales of assets	—	38,000
Capital expenditures	(37,199)	(51,211)
Net cash used in investing activities	(37,199)	(13,211)
FINANCING ACTIVITIES		
Proceeds from Note Payable, TEPPCO Midstream Companies, LLC	—	66,375
Repayments of Note Payable, TEPPCO Midstream Companies, LLC	—	(96,990)
Contributions from partners	34,592	20,000
Distributions paid to partners	(109,706)	(98,646)
Net cash used in financing activities	(75,114)	(109,261)
NET CHANGE IN CASH AND CASH EQUIVALENTS	11,459	(62)
CASH AND CASH EQUIVALENTS, JANUARY 1	—	62
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 11,459	$ —

See Notes to Consolidated Financial Statements.

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JONAH GAS GATHERING COMPANY AND SUBSIDIARY

STATEMENTS OF CONSOLIDATED PARTNERS' CAPITAL
(Dollars in thousands)

	TEPPCO GP, Inc.	TEPPCO Midstream Companies, LLC	Enterprise Gas Processing, LLC	Total
BALANCE AT DECEMBER 31, 2005	$ 3	$ 294,862	$ —	$ 294,865
Net income	1	88,794	238	89,033
Contributions from partners	—	418,840	116,874	535,714
Distributions to partners	—	(110,162)	(200)	(110,362)
Transfer of partnership interest	(4)	4	—	—
BALANCE AT DECEMBER 31, 2006	—	692,338	116,912	809,250
Net income	—	83,702	9,418	93,120
Contributions from partners	—	184,627	108,884	293,511
Distributions to partners	—	(88,539)	(9,451)	(97,990)
BALANCE AT DECEMBER 31, 2007	$ —	$ 872,128	$225,763	$1,097,891

See Notes to Consolidated Financial Statements.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization

Jonah Gas Gathering Company ("Jonah"), a Wyoming general partnership, owns a 643 mile natural gas gathering system known as the "Jonah Gas Gathering System" in the Green River Basin of southwestern Wyoming. Jonah has life of lease agreements with natural gas producers in the Jonah and Pinedale fields to provide gathering services to the producers. As used in these financial statements, "we," "us," or "Jonah" are intended to mean Jonah Gas Gathering Company and, where the context requires, include our subsidiary, Jonah Gas Marketing, LLC ("JGM"), a Delaware limited liability company.

The Jonah Gas Gathering System was originally constructed in 1992. Prior to June 1, 2000, Jonah was a subsidiary of McMurry Oil Company. On June 1, 2000, in connection with Alberta Energy Company's ("AEC") purchase of McMurry Oil Company, AEC acquired all of the outstanding partnership interests in Jonah for cash consideration and the assumption of debt, for an aggregate cost of approximately $208.0 million.

On September 30, 2001, TEPPCO Partners, L.P. ("TEPPCO"), a publicly traded Delaware limited partnership, through its affiliates, TEPPCO GP, Inc. ("TEPPCO GP") and TEPPCO Midstream Companies, LLC (formerly TEPPCO Midstream Companies, L.P. and referred to herein as "TEPPCO Midstream"), purchased Jonah from AEC for $360.0 million. TEPPCO's general partner was an indirect wholly owned subsidiary of DCP Midstream Partners, L.P. (formerly Duke Energy Field Services, LLC) ("DCP"), a joint venture between Duke Energy Corporation and ConocoPhillips. DCP managed and operated the Jonah assets for TEPPCO under a contractual agreement.

TEPPCO Midstream is owned 99.999% by TEPPCO and 0.001% by TEPPCO GP. TEPPCO GP is wholly owned by TEPPCO. TEPPCO Midstream owned a 99.999% interest in Jonah and TEPPCO GP owned a 0.001% interest in Jonah.

On February 24, 2005, TEPPCO's general partner was acquired by DFI GP Holdings L.P., ("DFIGP") an affiliate of EPCO, Inc. ("EPCO"), a privately held company controlled by Dan L. Duncan. On May 7, 2007, DFIGP sold all of the membership interests in TEPPCO's general partner to Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded partnership, also controlled by Dan L. Duncan. Mr. Duncan and certain of his affiliates, including Dan Duncan LLC and privately held companies controlled by him, control TEPPCO and its general partner. In conjunction with an amended and restated administrative services agreement, EPCO performs all management, administrative and operating functions required for TEPPCO,,and TEPPCO reimburses EPCO for all direct and indirect expenses that have been incurred in its management. TEPPCO assumed the operations of Jonah from DCP, and certain employees of DCP became employees of EPCO effective June 1, 2005. On August 18, 2005, TEPPCO formed JGM to conduct marketing activities for Jonah. TEPPCO Midstream was the sole member of JGM.

Since TEPPCO's acquisition of Jonah in 2001, the pipeline capacity and processing capacity of the Jonah system has been expanded in four phases, increasing system capacity from approximately 450 million cubic feet per day ("MMcf/d") to approximately 1.5 billion cubic feet per day ("Bcf/d"), adding 130 miles of pipeline and 36,700 horsepower of compression at an aggregate cost of approximately $242.7 million. As described in more detail below, TEPPCO and Enterprise Products Partners are working to complete the Phase V expansion of the system during April 2008.

Formation of Joint Venture

On August 1, 2006, TEPPCO GP and TEPPCO Midstream entered into an Amended and Restated Partnership Agreement of Jonah Gas Gathering Company (the "Partnership Agreement") with Enterprise Gas Processing, LLC ("EGP"), a subsidiary of Enterprise Products Partners in order to fund the Phase V expansion and

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

any further expansion of the Jonah Gas Gathering System. Enterprise Products Partners is a publicly traded Delaware limited partnership, and an affiliate of Enterprise GP Holdings, which is the sole member of TEPPCO's general partner. Under the Partnership Agreement, EGP was admitted as a new partner in exchange for funding a portion of the costs related to an expansion of the Jonah Gas Gathering System. On August 1, 2006, in connection with the admission of EGP into the Jonah partnership, TEPPCO Midstream acquired the Jonah partnership interest previously owned by TEPPCO GP and contributed all of its interest in JGM to Jonah. Effective August 1, 2006, Jonah owns all of the outstanding membership interests in JGM, and TEPPCO Midstream holds all of the partnership interest in Jonah that was previously held by TEPPCO GP.

EGP is the operator of the Jonah assets. Jonah is governed by a management committee comprised of two representatives approved by Enterprise Products Partners and two representatives approved by TEPPCO, each with equal voting power.

In February 2006, Enterprise Products Partners assumed the management of the Phase V expansion project and funded the initial costs of the expansion. Beginning with the August 1, 2006 formation of the Jonah joint venture, TEPPCO reimbursed Enterprise Products Partners for 50% of the expansion costs Enterprise Products Partners had previously advanced, and TEPPCO and Enterprise Products Partners began sharing the costs of the expansion equally.

In connection with the joint venture arrangement, TEPPCO and Enterprise Products Partners are continuing the Phase V expansion, which is expected to increase the system capacity from 1.5 Bcf/d to approximately 2.35 Bcf/d and to significantly reduce system operating pressures. The first portion of the expansion, included a pipeline loop of 75 miles of 36-inch diameter pipe and 12 miles of 24-inch diameter pipe that was completed in December 2006, increased the system gathering capacity to approximately 2.0 Bcf/d and was completed in July 2007. The second and final portion of the expansion is expected to be completed during April 2008 and is expected to increase the system gathering capacity to approximately 2.35 Bcf/d. The total anticipated cost of the Phase V expansion is expected to be approximately $505.0 million.

From August 1, 2006 through July 2007, TEPPCO and Enterprise Products Partners equally shared the costs of the Phase V expansion, and beginning in December 2006 with the completion of a portion of the expansion (discussed above), Enterprise Products Partners began sharing in the incremental cash flow and distributions resulting from the operation of those new facilities. During August 2007, with the completion of the first portion of the expansion, TEPPCO and Enterprise Products Partners began sharing partnership cash distributions and earnings based upon a formula that takes into account the capital contributions of both parties, including expenditures by TEPPCO prior to the expansion. Based on this formula in the Partnership Agreement, at December 31, 2007, TEPPCO's ownership interest in Jonah was approximately 80.64% and Enterprise Products Partners' ownership interest was approximately 19.36%. To the extent the Phase V expansion costs exceed an agreed upon base cost estimate of $415.2 million, TEPPCO and Enterprise Products Partners will each pay their respective ownership share (approximately 80% and 20%, respectively). Final ownership in Jonah is currently anticipated to remain at these levels.

Note 2. Summary of Significant Accounting Policies

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

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Accounts Receivable and Allowance for Doubtful Accounts

Our customers primarily consist of companies within the petroleum industry. We perform ongoing credit evaluations of our customers and generally do not require material collateral. A provision for losses on accounts receivable is established if it is determined that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly, and an allowance is established or adjusted, as necessary, using the specific identification method. As of December 31, 2007 and 2006, we had no provision for doubtful accounts.

Asset Retirement Obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from its acquisition, construction, development and/or normal operation. We record a liability for AROs when incurred and capitalize an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over its useful life. We will either settle our ARO obligations at the recorded amount or incur a gain or loss upon settlement (see Note 6).

Basis of Presentation and Principles of Consolidation

The financial statements include our accounts on a consolidated basis. We have eliminated all intercompany items in consolidation. Our results for the year ended December 31, 2006 reflect the operations and activities of our Pioneer plant as discontinued operations.

Cash and Cash Equivalents

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

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

Contingencies

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

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

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. At December 31, 2007 and 2006, we had no liabilities for loss contingencies.

Dollar Amounts

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

Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Fair Value of Current Assets and Current Liabilities

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

Goodwill

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

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

Income Taxes

We are a general partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from the net income or net loss reported in the net income or net loss reported in our statement of income, is includable in the federal and state income tax returns of each partner. Accordingly, no recognition has been given to federal or state income taxes for our operations.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Intangible Assets

Intangible assets consist of gathering contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming. The value assigned to these intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production to the gathering system. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 4).

Natural Gas Imbalances

Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas volumes to our gathering system than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. If the customers supply more natural gas volumes than they nominated, Jonah records a payable for the amount due to customers and also records a receivable for the same amount due from connecting pipeline transporters or shippers. If the customers supply less natural gas volumes than they nominated, Jonah records a receivable reflecting the amount due from customers and a payable for the same amount due to connecting pipeline transporters or shippers. We record these natural gas imbalances using average market prices, which is representative of the estimate value of the imbalances upon final settlement.

Operating, General and Administrative Expenses

EPCO allocates operating, general and administrative expenses to us for administrative, management, engineering and operating services based upon the estimated level of effort devoted to our various operations. We believe that the method for allocating corporate operating, general and administrative expenses is reasonable. Unless noted otherwise, our agreements with TEPPCO and EPCO are not on an arm’s length basis. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

Property, Plant and Equipment

Property, plant and equipment is recorded at its acquisition cost. Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance expense. Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum).

We evaluate impairment of long-lived assets in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated 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 estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell.

Revenue Recognition

Gathering revenues are recognized as natural gas is received from the customer. We generally do not take title to the natural gas, except for the wellhead sale and purchase of natural gas to facilitate system operations and to provide a service to some of the producers on the system. Jonah sells condensate liquid from the natural gas stream based on a contracted price based generally on an index based crude oil price less a differential. In May 2006, we began to aggregate purchases of wellhead gas on Jonah and re-sell the aggregate quantities at key Jonah delivery points in order to facilitate operational needs and throughput on Jonah. The purchases and sales are generally contracted with various parties to occur in the same month to minimize price risk. Revenues associated with condensate sales are recognized when the product is sold.

Note 3. Recent Accounting Developments

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Certain requirements of SFAS 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS 157 has been deferred for one year. We adopted the provisions of SFAS 157 which are effective for fiscal years beginning after November 15, 2007, and there was no impact on our financial statements. We are currently evaluating the impact that the deferred provisions of SFAS 157 will have on the disclosures in our financial statements in 2009.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115*. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes the company elects for similar types of assets and liabilities. As a calendar year-end entity, we adopted SFAS 159 on January 1, 2008. Our adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows since we did not elect to fair value any of our eligible financial assets or liabilities.

Note 4. Goodwill and Intangible Assets

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill, but instead requires testing for impairment at least annually. We test goodwill for impairment annually at December 31.

To perform an impairment test of goodwill, we determined we have one reporting unit. We determine the carrying value and the fair value of the reporting unit and compare them. We will continue to compare the fair value of the reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142. The recorded value of goodwill was $2.8 million for each of the years ended December 31, 2007 and 2006, respectively.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Other Intangible Assets

We had intangible assets (natural gas gathering contracts) with a gross carrying amount of $222.8 million for each of the years ended December 31, 2007 and 2006. Accumulated amortization was $74.0 million and $62.5 million for the years ended December 31, 2007 and 2006, respectively. SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $11.5 million and $9.8 million for the years ended December 31, 2007 and 2006, respectively.

The values assigned to the intangible assets for natural gas gathering contracts are amortized on a unit-of-production basis, based upon the actual throughput of the system compared to the expected total throughput for the lives of the contracts. From time to time, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the system, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. Revisions to these estimates may occur as additional production information is made available to us.

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

2008	$15,310
2009	17,156
2010	18,501
2011	18,638
2012	18,102

Note 5. Related Party Transactions

We have no employees. As a result of the change in ownership of TEPPCO's general partner on February 24, 2005, EPCO assumed the management of us on June 1, 2005. Beginning June 1, 2005, in conjunction with an amended and restated administrative services agreement (see Note 1), EPCO performs all management, administrative and operating functions required for us and we reimburse EPCO for all direct and indirect expenses that have been incurred in our management. The expenses associated with these management and operations services are reflected in costs and expenses in the accompanying statements of income.

We sell natural gas relating to our natural gas marketing activities to our partners and their affiliates. We also sell condensate liquid from the natural gas stream of the Jonah Gas Gathering System to our partners and their affiliates.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Revenues and expenses from TEPPCO and EPCO and their respective affiliates consist of the following:

	For Year Ended December 31, 2007	2006
Revenues and Expenses from TEPPCO and affiliates:		
Sales of natural gas liquids (“NGLs”)(1)	$ —	$ 3,764
Other operating revenues (2)	5,341	4,622
Operating expense (3)	501	—
Revenues and Expenses from EPCO and affiliates:		
Sales of natural gas	$ 4,887	$ 8,585
Purchases of natural gas (4)	542	251
Gain on sale of Pioneer plant	—	17,872
Operating expense (5)	8,965	6,149

(1) Includes NGL sales to TEPPCO Crude Oil, LLC (“TCO”) from our Pioneer processing plant prior to its sale to an affiliate of Enterprise Products Partners. These sales are classified as income from discontinued operations in the accompanying statements of consolidated income.

(2) Includes condensate sales to TCO.

(3) Includes supplies purchased from Lubrication Services, LLC, a subsidiary of TEPPCO.

(4) Includes processing fees paid to Enterprise Products Partners for processing services performed at the Pioneer processing plant after its sale to a subsidiary of Enterprise Products Partners.

(5) Includes payroll, payroll related expenses, administrative expenses, including reimbursements related to employee benefits and employee benefit plans, and other operating expenses incurred in managing us and our subsidiary.

Our related party accounts receivable and related party accounts payable that are included on the balance sheets consist of the following:

	December 31, 2007			December 31, 2006		
	Accounts Receivable	Accounts Payable	Other Current Liabilities (1)	Accounts Receivable	Accounts Payable	Other Current Liabilities (1)
Partners:						
TEPPCO	$ —	$ 6,033	$ —	$ 879	$ —	$ —
Enterprise Products Partners and affiliates	845	940	1,625	1,613	185	643
Total	$ 845	$ 6,973	$ 1,625	$ 2,492	$ 185	$ 643

(1) Relates to pipeline imbalances with a subsidiary Enterprise Products Partners.

Note 6. Property, Plant and Equipment

Major categories of property, plant and equipment at December 31, 2007 and 2006 were as follows:

	Estimated Useful Life In Years	December 31, 2007	December 31, 2006
Plants and pipelines	5-40(1)	$ 681,772	$ 373,117
Underground and other storage facilities	20-40	6,183	5,718
Transportation equipment		590	—
Land and right of way		54,720	20,893
Construction work in progress		228,686	276,421
Total property, plant and equipment		$ 971,951	$ 676,149
Less accumulated depreciation		61,553	42,690
Property, plant and equipment, net		$ 910,398	$ 633,459

(1) The estimated useful lives of major components of this category are as follows: pipelines, 20-40 years (with some equipment at 5 years); office furniture and equipment, 5-10 years and buildings, 20-40 years.

Depreciation expense on property, plant and equipment was $19.2 million and $9.8 million for the years ended December 31, 2007 and 2006, respectively. Interest capitalized was $1.6 million for the year ended December 31, 2006.

We regularly review our long-lived assets for impairment in accordance with SFAS 144. We have identified no long-lived assets that would require impairment as of December 31, 2007.

Asset Retirement Obligations

We have recorded a $0.3 million liability, which represents the fair value of conditional AROs related to the retirement of the Jonah Gas Gathering System. During the third quarter of 2006, we assigned probabilities for settlement dates and settlement methods for use in an expected present value measurement of fair value and recorded AROs. The following table presents information regarding our AROs:

ARO liability balance, December 31, 2005	$ —
Liabilities incurred	186
Accretion expense	5
ARO liability balance, December 31, 2006	191
Liabilities incurred	48
Accretion expense	25
ARO liability balance, December 31, 2007	$ 264

Property, plant and equipment at December 31, 2007, includes $0.2 million of asset retirement costs capitalized as an increase in the associated long-lived asset. Additionally, based on information currently available, we estimate that accretion expense will approximate $24 thousand for 2008, $26 thousand for 2009, $29 thousand for 2010, $31 thousand for 2011 and $34 thousand for 2012.

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Note 7. Dispositions and Discontinued Operations

On March 31, 2006, we sold our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with our rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners for $38.0 million in cash. The Pioneer plant was not an integral part of our operations, and natural gas processing is not a core business. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and recommended for approval by the Audit, Conflicts and Governance Committee of the Board of Directors of TEPPCO's general partner and a fairness opinion was rendered by an investment banking firm. The sales proceeds were used to fund organic growth projects, retire debt and for other general partnership purposes. The carrying value of the Pioneer plant at March 31, 2006, prior to the sale, was $19.7 million. Costs associated with the completion of the transaction were approximately $0.4 million.

A condensed statement of income for the Pioneer plant, which is classified as discontinued operations, for the year ended December 31, 2006, is presented below:

	For Year Ended December 31, 2006
Operating revenues:	
Sales of NGLs	$ 3,828
Other	932
Total operating revenues	4,760
Costs and expenses:	
Purchases of natural gas	3,000
Operating expense	182
Depreciation	51
Taxes – other than income taxes	30
Total costs and expenses	3,263
Income from discontinued operations	$ 1,497

Net cash provided by discontinued operations for the year ended December 31, 2006 is presented below:

	For Year Ended December 31, 2006
Cash flows from discontinued operating activities:	
Net income	$ 19,369
Depreciation and amortization	51
Gain on sale of Pioneer plant	(17,872)
Increase in inventories	(27)
Net cash provided by discontinued operations	$ 1,521

Note 8. Debt Obligations

Prior to August 1, 2006, we utilized debt financing available from TEPPCO. We had a note payable to TEPPCO Midstream, which represented borrowings under TEPPCO's Revolving Credit Facility, 7.625% Senior Notes and 6.125% Senior Notes. The terms of the intercompany note payable to TEPPCO Midstream generally matched the principal and interest payment dates under TEPPCO's credit agreement and senior notes. The interest rates charged by TEPPCO included its stated interest rate, plus a premium to cover debt issuance costs. The interest rate was also decreased or increased to cover gains and losses, respectively, on any interest rate swaps that TEPPCO had in place on its credit agreement and senior notes. Through July 31, 2006, Jonah (and certain other subsidiaries of TEPPCO) provided full, unconditional and joint and several guarantees of TEPPCO's senior notes and revolving credit facility. Effective August 1, 2006, with the formation of the joint venture between TEPPCO and Enterprise Products Partners, Jonah was released as a guarantor of TEPPCO's senior notes and revolving credit facility.

Effective August 1, 2006, in connection with the formation of the joint venture with Enterprise Products Partners, amounts outstanding of $231.2 million under the intercompany note payable to TEPPCO Midstream were converted to capital contributions and reclassified as partners' capital. For the period from January 1, 2006 through July 31, 2006, interest costs incurred on the note payable to TEPPCO Midstream totaled $8.4 million.

Note 9. Partners' Capital and Distributions

Prior to August 1, 2006, we made quarterly cash distributions of amounts established by TEPPCO in its sole discretion. We paid distributions of 99.999% to TEPPCO Midstream and 0.001% to TEPPCO GP.

Effective August 1, 2006, in connection with the formation of the joint venture between TEPPCO and EGP, our Partnership Agreement was amended and restated. We paid distributions 100% to TEPPCO until specified milestones were met in the Phase V expansion in December 2006. At that point, EGP became entitled to receive approximately 50% of the incremental cash flow from certain portions of the expansion project already placed in service. During August 2007, with the completion of the next specified milestone (as defined in the partnership agreement), EGP began to share in the revenues of the joint venture based upon a formula that took into account the total amount of its capital contributions. As discussed in Note 1, the final ownership in the joint venture is approximately 80.64% TEPPCO and approximately 19.36% EGP.

For the year ended December 31, 2007, cash distributions paid to TEPPCO Midstream and EGP, which included distributions payable at December 31, 2006, totaled $100.0 million and $9.7 million, respectively. For the year ended December 31, 2006, cash distributions paid to TEPPCO Midstream totaled $98.6 million. No cash distributions were paid to EGP in 2006. At December 31, 2006, we had a distribution payable of $11.5 million and $0.2 million to TEPPCO Midstream and EGP, respectively.

For the year ended December 31, 2007, we received contributions of $184.6 million and $108.9 million from TEPPCO Midstream and EGP, respectively. For the year ended December 31, 2006, we received contributions of $418.8 million and $116.9 million from TEPPCO Midstream and EGP, respectively. The contribution amounts for the years ended December 31, 2007 and 2006, included $258.9 million and $243.7 million, respectively, of non-cash contributions from TEPPCO Midstream and EGP related to the Phase V expansion. Additionally, the non-cash contribution from TEPPCO Midstream for the year ended December 31, 2006, included $231.2 million related to the transfer of the note payable with TEPPCO Midstream to partners' capital and $19.9 million for the related accrued interest, which occurred upon formation of the joint venture with EGP on August 1, 2006. On August 1, 2006, effective with the formation of the joint venture, the balance in our accounts payable, related parties of $20.9 million was transferred to partners' capital as non-cash contributions.

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Note 10. Commitments and Contingencies

Legal Proceedings

Williams Gas Processing, n/k/a Williams Field Services Company, LLC (“Williams”) notified Jonah that the gas delivered to Williams’ Opal Gas Processing Plant (“Opal Plant”) allegedly fails to conform to quality specifications of the Interconnect and Operator Balancing Agreement (“Interconnect Agreement”) which has caused damages to the Opal Plant in excess of $15 million. On July 24, 2007, Jonah filed suit against Williams in Harris County, Texas seeking a declaratory order that Jonah was not liable to Williams. In addition, on August 24, 2007, Williams filed a complaint in the 3rd Judicial District Court of Lincoln County, Wyoming alleging that Jonah was delivering non-conforming gas from its gathering customers in the Jonah gas gathering system to the Opal Plant, in violation of the Interconnect Agreement. Jonah denies any liability to Williams.

In addition to the proceedings discussed above, we are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, management believes these claims will not have a material effect on the financial position, results of operations or cash flows.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2007. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
	Total	2008	2009	2010	2011	2012	Thereafter
Operating leases (1)	$167	$ 89	$78	$—	$—	$—	$—
Purchase obligations (2)	39	4	4	4	4	4	19
Capital expenditure obligations (3)	178	178	—	—	—	—	—

(1) We use leased assets in several areas of our operations. Total rental expense for the years ended December 31, 2007 and 2006, was $0.8 million and $1.0 million, respectively.

(2) We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The preceding table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at December 31, 2007.

(3) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services rendered or products purchased.

Note 11. Concentrations of Credit Risk

Our primary market area is located in the western region of the United States. We have a concentration of trade receivable balances due from major integrated oil and gas companies and large to medium-sized independent producers. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors. We thoroughly analyze our customers’ historical and future credit positions prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments and guarantees.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

For the year ended December 31, 2007, Encana Oil and Gas (USA) Inc., BP Energy Company, Sempra Energy Trading Corporation and Shell Rocky Mountain Production, LLC accounted for 29%, 23%, 16% and 11%, respectively, of our total consolidated revenues. For the year ended December 31, 2006, Encana Oil and Gas (USA) Inc., BP Energy Company and Shell Rocky Mountain Production, LLC accounted for 31%, 30% and 10%, respectively, of our total consolidated revenues. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2007 and 2006.

Note 12. Supplemental Cash Flow Information

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities, (ii) non-cash investing activities and (iii) cash payments for interest for the years ended December 31, 2007 and 2006:

	For Year Ended December 31, 2007	For Year Ended December 31, 2006
Decrease (increase) in:		
Accounts receivable, trade	$ (10,607)	$ (6,232)
Accounts receivable, related parties	1,647	(2,492)
Inventories	(398)	254
Other current assets	(616)	13,675
Other	697	(662)
Increase (decrease) in:		
Accounts payable and accrued expenses	2,256	(3,202)
Accounts payable, related parties	6,973	30,113
Other	—	(50)
Net effect of changes in operating accounts	$ (48)	$ 31,404
Non-cash financing activities:		
Non-cash contributions from partners for Phase V expansion	$ 258,919	$ 243,718
Distributions payable to partners	—	11,716
Contribution of Note Payable, TEPPCO Midstream Companies, LLC to partners' capital	—	231,220
Contribution of accrued interest to partners' capital	—	19,900
Contribution of accounts payable, related party to partners' capital	—	20,876
Supplemental disclosure of cash flows:		
Cash paid for interest (net of amounts capitalized)	$ —	$ 6,188

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LDH Energy Mont Belvieu L.P. (Formerly Mont Belvieu Storage Partners, L.P.)

Financial Statements As of and for the Two Months Ended February 28, 2007 and the Years Ended December 31, 2006 and 2005, and Independent Auditors' Report

LDH ENERGY MONT BELVIEU L.P.

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INDEPENDENT AUDITORS' REPORT

To the Partners of
LDH Energy Mont Belvieu L.P.:

We have audited the accompanying balance sheets of LDH Energy Mont Belvieu L.P. (formerly Mont Belvieu Storage Partners, L.P.) (the "Partnership") as of February 28, 2007 and December 31, 2006, and the related statements of income, partners' equity, and cash flows for the periods then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Partnership at February 28, 2007 and December 31, 2006, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Houston, Texas
February 15, 2008

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LDH ENERGY MONT BELVIEU L.P.

BALANCE SHEETS
FEBRUARY 28, 2007 AND DECEMBER 31, 2006
(Dollars in thousands)

	February 28, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 18,993	$ 12,599
Accounts receivable – trade	2,853	2,746
Accounts receivable – related parties	127	3,131
Other current assets	374	516
Total current assets	22,347	18,992
PROPERTY, PLANT AND EQUIPMENT, AT COST (net of accumulated depreciation of $16,403 and $15,651)	90,144	90,563
INTANGIBLE ASSETS (net of accumulated amortization of $7,531 and $7,325)	10,332	10,538
OTHER LONG-TERM ASSETS	1	1
TOTAL ASSETS	$ 122,824	$ 120,094
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 2,900	$ 464
Accrued taxes other than income	424	1,652
Total current liabilities	3,324	2,116
COMMITMENTS AND CONTINGENCIES (NOTE 5)		
PARTNERS' EQUITY	119,500	117,978
TOTAL LIABILITIES AND PARTNERS' EQUITY	$ 122,824	$ 120,094

See Notes to Financial Statements.

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LDH ENERGY MONT BELVIEU L.P.

STATEMENTS OF INCOME
FOR THE TWO MONTHS ENDED FEBRUARY 28, 2007
AND THE YEARS ENDED DECEMBER 31, 2006 AND 2005
(Dollars in thousands)

	February 28, 2007	December 31, 2006	December 31, 2005 (unaudited)
OPERATING REVENUES:			
Storage revenue	$ 3,000	$ 17,200	$ 16,029
Shuttle revenue	1,917	6,865	6,014
Other	2,076	10,664	9,872
Total operating revenues	6,993	34,729	31,915
COSTS AND EXPENSES:			
Operating, general and administrative	3,322	6,611	8,477
Operating fuel and power	851	5,187	2,915
Depreciation and amortization	958	6,890	7,512
Taxes – other than income taxes	390	1,560	1,895
Total costs and expenses	5,521	20,248	20,799
OPERATING INCOME	1,472	14,481	11,116
OTHER INCOME	127	548	440
Income before provision for income taxes	1,599	15,029	11,556
PROVISION FOR INCOME TAXES	77	—	—
NET INCOME	$ 1,522	$ 15,029	$ 11,556

See Notes to Financial Statements.

LDH ENERGY MONT BELVIEU L.P.

STATEMENTS OF CASH FLOWS
FOR THE TWO MONTHS ENDED FEBRUARY 28, 2007
AND THE YEARS ENDED DECEMBER 31, 2006 AND 2005
(Dollars in thousands)

	February 28, 2007	December 31, 2006	December 31, 2005 (unaudited)
OPERATING ACTIVITIES:			
Net income	$ 1,522	$ 15,029	$ 11,556
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	958	6,890	7,512
Net effect of changes in operating accounts:			
(Increase) decrease in accounts receivable – trade	(9)	426	(682)
Decrease (increase) in accounts receivable – related parties	2,906	(2,952)	(61)
Decrease (increase) in other current assets	142	676	(778)
Decrease (increase) in other long-term assets	—	17	(18)
Increase (decrease) in accounts payable and accrued liabilities	2,436	(1,556)	720
(Decrease) increase in accounts payable, related parties	—	(899)	(428)
(Decrease) increase in accrued taxes other than income	(1,228)	(217)	1,684
(Decrease) increase in long-term liabilities	—	(330)	182
Net cash provided by operating activities	6,727	17,084	19,687
INVESTING ACTIVITIES:			
Capital expenditures	(333)	(4,794)	(7,304)
Net cash used in investing activities	(333)	(4,794)	(7,304)
FINANCING ACTIVITIES:			
Contributions	—	5,347	4,682
Distributions	—	(19,395)	(17,895)
Net cash used in financing activities	—	(14,048)	(13,213)
NET CHANGE IN CASH AND CASH EQUIVALENTS	6,394	(1,758)	(830)
CASH AND CASH EQUIVALENTS — January 1	12,599	14,357	15,187
CASH AND CASH EQUIVALENTS — February 28 and December 31	$ 18,993	$ 12,599	$ 14,357
NON-CASH INVESTING ACTIVITIES:			
Net assets contributed from TE Products	$ —	$ —	$ 1,429
Net assets distributed to TE Products	—	603	—

See Notes to Financial Statements.

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LDH ENERGY MONT BELVIEU L.P.

STATEMENTS OF PARTNERS' EQUITY
FOR THE TWO MONTHS ENDED FEBRUARY 28, 2007
AND THE YEARS ENDED DECEMBER 31, 2006 AND 2005
(Dollars in thousands)

	TE Products Pipeline Company, LLC (1)	Louis Dreyfus Energy Services L.P.	LDH Energy Mont Belvieu GP LLC (2)	Total
BALANCE — December 31, 2004 (unaudited)	$ 84,330	$ 32,854	$ 644	$117,828
Net income	7,402	4,058	96	11,556
Contributions	5,663	448	—	6,111
Distributions	(12,382)	(5,513)	—	(17,895)
BALANCE — December 31, 2005 (unaudited)	85,013	31,847	740	117,600
Net income	8,868	6,028	133	15,029
Contributions	4,767	580	—	5,347
Distributions	(13,525)	(6,473)	—	(19,998)
BALANCE — December 31, 2006	85,123	31,982	873	117,978
Net income	1,030	481	11	1,522
Contributions	—	—	—	—
Distributions	—	—	—	—
BALANCE — February 28, 2007	$ 86,153	$ 32,463	$ 884	$119,500

(1) Formerly TE Products Pipeline Company, Limited Partnership.

(2) Formerly Mont Belvieu Venture, LLC.

See Notes to Financial Statements.

LDH ENERGY MONT BELVIEU L.P.

NOTES TO FINANCIAL STATEMENTS
FEBRUARY 28, 2007 AND DECEMBER 31, 2006 AND 2005 (Unaudited)

1. ORGANIZATION

In February 2000, TE Products Pipeline Company, LLC (formerly TE Products Pipeline Company, Limited Partnership) ("TE Products") entered into a joint development agreement ("Development Agreement") with Louis Dreyfus Plastics Corporation, now known as Louis Dreyfus Energy Services L.P. ("Louis Dreyfus"), in which TE Products' Mont Belvieu liquefied petroleum gas ("LPG") storage and shuttle transportation system was jointly marketed by Louis Dreyfus and TE Products under the terms provided in the Development Agreement. The purpose of the Development Agreement was 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 by establishing new receipt and delivery connections. The Development Agreement provided for a service-oriented, fee-based venture with no commodity trading activity. TE Products operated the facilities under the Development Agreement. The Development Agreement stipulated that if certain earnings thresholds were achieved, a partnership between TE Products and Louis Dreyfus was to be created effective January 1, 2003. All terms and earnings thresholds of the Development Agreement were met; therefore, as of January 1, 2003, TE Products and Louis Dreyfus formed LDH Energy Mont Belvieu L.P. (formerly Mont Belvieu Storage Partners, L.P.) (the "Partnership"). The economic terms of the Partnership were the same under the partnership agreement ("Partnership Agreement") as those under the Development Agreement. TE Products contributed property, plant, and equipment with a net book value of $67.0 million to the Partnership. TE Products, a wholly owned subsidiary of TEPPCO Partners, L.P. ("TEPPCO"), operated the facilities for the Partnership.

Louis Dreyfus invested $6.1 million for expansion projects at Mont Belvieu that TE Products was required to reimburse if the original Development Agreement was terminated by either party. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in the Partnership. TE Products and Louis Dreyfus each held a 49.5% interest in the Partnership as a limited partner and a 50% interest in LDH Energy Mont Belvieu GP LLC (formerly Mont Belvieu Venture, LLC,) the general partner ("General Partner") of the Partnership; however, income and distributions were shared as described in Note 11.

The Partnership has approximately 36 million barrels of LPGs storage capacity and approximately 7 million barrels of refined products storage capacity, including storage capacity leased to outside parties, at the Mont Belvieu fractionation and storage complex. The Partnership includes a short-haul transportation shuttle system, consisting of a complex system of pipelines and interconnects, that ties Mont Belvieu, Texas to refinery and petrochemical facilities on the upper Texas Gulf Coast. The Partnership also provides truck and rail car loading capability.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounts Receivable and Allowance for Doubtful Accounts — The Partnership's customers primarily consist of companies within the petroleum industry. The Partnership performs ongoing credit evaluations of its customers and generally does not require material collateral. Trade accounts receivable are recorded at the invoiced amount and do not bear interest. A provision for losses on accounts receivable is established if it is determined that the Partnership will not collect all or part of the outstanding balance. Collectibility is reviewed regularly, and an allowance is established or adjusted, as necessary, using the specific identification method.

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

The Partnership's assets consist primarily of a series of intrastate pipelines and storage facilities along the upper Texas Gulf Coast. The Partnership has determined that it is obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of the Partnership assets. However, the Partnership is not able to reasonably determine the fair value of the AROs since future dismantlement and removal dates are indeterminate. It is impossible to predict when demand for storage or transportation of the related products will cease. The Partnership will record such AROs in the period in which more information becomes available for the Partnership to reasonably estimate the settlement dates of the AROs.

Cash and Cash Equivalents — Cash and cash equivalents represent unrestricted cash on hand and all highly liquid marketable securities with maturities of three months or less when purchased. The carrying value of cash equivalents approximates fair value because of the short-term nature of these investments.

The Partnership's statements of cash flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

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

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in the

Partnership's financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. At February 28, 2007 and December 31, 2006, the Partnership had no liabilities for loss contingencies.

Contribution of Assets — Assets contributed to the Partnership are valued at the net book value of the assets at the time of contribution.

Estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Although the Partnership believes these estimates are reasonable, actual results could differ from these estimates.

Fair Value of Current Assets and Current Liabilities — The carrying amount of cash and cash equivalents, accounts receivable, other current assets, accounts payable and accrued liabilities, and other current liabilities approximates their fair value due to their short-term nature. The fair values of these financial instruments are represented in the Partnership's balance sheets.

Income Taxes — The Partnership is a limited partnership. As such, the Partnership is not a taxable entity for federal and state income tax purposes and does not directly pay federal and state income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or net loss reported in the Partnership's statement of income, is includable in the federal and state income tax returns of each partner. Accordingly, no recognition has been given to federal or state income taxes for the Partnership's operations.

Revised Texas Franchise Tax – In May 2006, the State of Texas enacted a new business tax (the "Revised Texas Franchise Tax") that replaces its existing franchise tax. In general, legal entities that do business in Texas are subject to the Revised Texas Franchise Tax. Limited partnerships, limited liability companies, corporations, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the Revised Texas Franchise Tax. As a result of the change in tax law, the Partnership's tax status in the state of Texas changed from nontaxable to taxable. The Revised Texas Franchise Tax is considered an income tax for purposes of adjustments to deferred tax liability, as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. The Revised Texas Franchise Tax becomes effective for franchise tax reports due on or after January 1, 2008. The Revised Texas Franchise Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Revised Texas Franchise Tax is assessed at 1% of Texas-sourced taxable margin measured by the ratio of gross receipts from business done in Texas to gross receipts from business done everywhere. The taxable margin is computed as the lesser of (i) 70% of total revenue or (ii) total revenues less (a) cost of goods sold or (b) compensation. The Revised Texas Franchise Tax is calculated, paid and filed at an affiliated unitary group level. Generally, an affiliated group is made up of one or more entities in which a controlling interest of more than 50% is owned by a common owner or owners. Generally, a business is unitary if it is characterized by a sharing or exchange of value between members of the group, and a synergy and mutual benefit all of the members of the group achieved by working together.

Since the Revised Texas Franchise Tax is determined by applying a tax rate to a base that considers both revenues and expenses, it has characteristics of an income tax. Accordingly, the Partnership determined the Revised Texas Franchise Tax should be accounted for as an income tax in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*.

For the two months ended February 28, 2007, the Partnership recorded a $0.1 million current tax liability. The offsetting charge is shown on the statement of income for the two months ended February 28, 2007 as provision for income taxes.

Accounting for Uncertainty in Income Taxes – In accordance with Financial Accounting Standards Board ("FASB") Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, the Partnership must recognize the tax effects of any uncertain tax positions it may adopt, if the position taken by it is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by the Partnership would be the largest amount of benefit with more than a 50% chance of being realized upon ultimate settlement with a taxing authority with full knowledge of all relevant information. This guidance was effective January 1, 2007, and the adoption of this guidance had no material impact on the Partnership's financial position, results of operations or cash flows.

Intangible Assets — Intangible assets consist of contracts assumed in the acquisition of three salt dome storage wells and other assets from ConocoPhillips on April 1, 2004. These contracts with customers are for various fixed terms and have various evergreen renewal provisions. These intangible assets are amortized on a straight-line basis, based upon the lives of the contracts assuming the various renewals are exercised. The acquired intangible assets have various useful lives ranging from 1 year to 11 years (see Note 8).

Property, Plant, and Equipment — The Partnership records property, plant, and equipment at cost. Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. The Partnership charges replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance expense. Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum).

The Partnership evaluates impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated 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 estimated fair value of the assets. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying amount or fair value less costs to sell, and would no longer be depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate asset and liability sections of the balance sheets.

Revenue Recognition — The Partnership's revenues are primarily earned from the storage and shuttling of LPGs. In addition, the Partnership receives revenue from fees charged on butane segregation, brine gathering, custody transfers, and other ancillary services. Storage revenues are recognized based on volumes stored during the period, and shuttling revenues are recognized as LPGs are out-loaded. Fee revenues are recognized when services are performed.

3. RECENT ACCOUNTING DEVELOPMENTS

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS 157 defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop the measurements, and the effect of certain of the measurements on earnings (or changes in net assets) for the period. Certain requirements of SFAS 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS 157 has been deferred for one year. We adopted the provisions of SFAS 157 which are effective for fiscal years beginning after November 15, 2007, and there was no impact on our financial statements. We are currently evaluating the impact that the deferred provisions of SFAS 157 will have on the disclosures in our financial statements in 2009.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115*. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. The Partnership adopted SFAS 159 on January 1, 2008. The Partnership's adoption of this guidance did not have a material impact on its financial condition, results of operations or cash flows since it did not elect to fair value any of its eligible financial assets or liabilities.

4. LEASE AGREEMENTS WITH CUSTOMERS

The Partnership has long-term storage contracts with various customers with terms ranging up to five years. These noncancelable operating leases have varying annual monthly payments and expiration dates. The Partnership recognized rental income from operating leases of $0.6 million, $6.5 million and $8.1 million for the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005, respectively.

The minimum future rentals to be received under noncancelable operating leases as of February 28, 2007 are as follows (in thousands):

2007	$ 3,883
2008	2,195
2009	1,998
2010	1,998
2011	540
Thereafter	—
Total	$ 10,614

5. COMMITMENTS AND CONTINGENCIES

Legal Proceedings — The Partnership is involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, the Partnership management believes these claims will not have a material effect on the financial position, results of operations or cash flows. The Partnership is not currently involved in any material claims or legal actions arising in the ordinary course of business.

Lease Commitments — The Partnership recognized no rental expense for operating leases for the two months ended February 28, 2007 and $0.2 million for each of the years ended December 31, 2006 and 2005. Commitments entered into prior to February 28, 2007 under noncancelable leases are immaterial subsequent to February 28, 2007.

6. RELATED-PARTY TRANSACTIONS

The Partnership has no employees and was managed by TE Products through February 28, 2007. TE Products operated the Partnership and was reimbursed by the Partnership in accordance with the terms of the Partnership Agreement for direct costs and expenses incurred on behalf of the Partnership. Corporate overhead costs were not allocated to the Partnership as TE Products' income sharing participation was designed to reimburse TE Products for such overhead (see Note 11).

For the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005, the Partnership has incurred $0.5 million, $2.9 million and $3.2 million, respectively, for direct payroll and payroll-related expenses from TE Products. At February 28, 2007 and December 31, 2006, the Partnership had a net receivable balance from TE Products of $0.2 million and $2.3 million, respectively, for advances for operating costs, including payroll and related expenses for operating the Partnership.

Effective January 1, 2003, TE Products and the Partnership entered into a pipeline capacity lease agreement, and for the two months ended February 28, 2007, the Partnership recognized a nominal amount in rental expense related to this lease agreement. For each of the years ended December 31, 2006 and 2005, the Partnership recognized $0.1 million in rental expense related to this lease agreement.

Effective January 1, 2003, the Partnership entered into an agreement with its affiliate, Louis Dreyfus, to store one million barrels of low sulfur diesel fuel at the Mont Belvieu complex. At February 28, 2007 and December 31, 2006, the Partnership had an outstanding receivable of $0.7 million and $0.8 million, respectively, from Louis Dreyfus related to this agreement.

Per the terms of the Partnership Agreement, TE Products may store up to four million barrels, 9% of a total capacity of 43 million barrels, of product at Mont Belvieu at no cost. This agreement was an accommodation to service TE Products' need for storage from its mainline products pipeline system, mainly for products owned by third-party customers in transit requiring temporary storage. The four million barrels was estimated to be the maximum amount of storage TE Products would need at any point both for its own products and products it was transporting for customers. Should TE Products exceed the need for four million barrels of storage capacity, TE Products would pay the market rate of storage for any excess barrels (see Note 12 regarding the sale of TE Products' interest in the Partnership).

7. PROPERTY, PLANT, AND EQUIPMENT

The components of property, plant, and equipment at February 28, 2007 and December 31, 2006 were (in thousands):

	Estimated Useful Life In Years	February 28, 2007	December 31, 2006
Land		$ 3,775	$ 3,775
Line pipe and fittings	30-40	36,180	36,529
Storage tanks and delivery facilities	30-40	38,326	38,326
Buildings and improvements	30-40	4,333	4,333
Machinery and equipment	5-10	16,888	16,896
Construction work in progress		4,340	4,734
Other		2,705	1,621
Total property, plant and equipment		$ 106,547	$ 106,214
Less accumulated depreciation		16,403	15,651
Net property, plant and equipment		$ 90,144	$ 90,563

Depreciation expense on property, plant and equipment was $0.8 million, $5.0 million and $4.8 million for the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005, respectively.

The Partnership regularly reviews its long-lived assets for impairment in accordance with SFAS 144. The Partnership has identified no long-lived assets that would require impairment as of February 28, 2007.

8. INTANGIBLE ASSETS

At February 28, 2007 and December 31, 2006, the Partnership's intangible assets comprised of customer contracts were (in thousands):

	February 28, 2007	December 31, 2006
Intangible assets	$ 17,863	$ 17,863
Less accumulated amortization	(7,531)	(7,325)
Net intangible assets	$ 10,332	$ 10,538

SFAS No. 142, *Goodwill and Other Intangible Assets*, requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense for amortizing intangible assets was $0.2 million, $1.9 million and $2.7 million for the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005, respectively.

The following table sets forth the estimated amortization expense of intangible assets (in thousands):

Years Ending December 31	
2007 (1)	$ 1,239
2008	1,239
2009	1,239
2010	1,239
2011	1,239
Thereafter	4,343
Total	$ 10,538

(1) Represents estimated amortization expense for the year ended December 31, 2007. Of this amount, $0.2 million has been recognized through February 28, 2007.

9. OTHER OPERATING REVENUE

The components of other operating revenue for the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005 were (in thousands):

	February 28, 2007	December 31, 2006	December 31, 2005 (unaudited)
Service revenue	$ 317	$ 2,221	$ 1,904
Butane segregation	61	361	615
Brine gathering fee	635	2,801	1,941
Custody transfers	687	2,534	2,621
Other	376	2,747	2,791
Total	$ 2,076	$ 10,664	$ 9,872

10. EMPLOYEE BENEFITS

The Partnership was charged for employee benefits costs related to the TEPPCO Retirement Cash Balance Plan (“TEPPCO RCBP”) which was a noncontributory, trustee-administered pension plan, and TEPPCO’s plans for healthcare and life insurance benefits for retired employees, which were on a contributory and noncontributory basis. Costs were allocated to the Partnership based on the level of effort provided by TE Products’ employees. The TEPPCO RCBP plan was terminated effective December 31, 2005 as a result of the acquisition of TEPPCO’s general partner interest by an affiliate of EPCO, Inc. (“EPCO”), and plan participants had the option to receive their benefits either through a lump sum payment in 2006 or through an annuity. For those plan participants who elected to receive an annuity, TEPPCO purchased an annuity contract from an insurance company in which the plan participant owns the annuity, absolving TEPPCO of any future obligation to the participant. EPCO maintained a 401(k) plan for the benefit of employees providing services to the Partnership, and the Partnership reimbursed EPCO for the cost of maintaining this plan.

11. PARTNERS' EQUITY

As specified in the Partnership Agreement, TE Products and Louis Dreyfus each held a 49.5% interest in the Partnership as a limited partner and a 50% interest in the General Partner of the Partnership. Capital accounts were the accounts established for TE Products, Louis Dreyfus, and the General Partner (collectively, the "Partners") for purposes of maintaining all items of the Partnership income, gain, loss, deduction, and credit that was allocated among the Partners as described below.

Capital Contribution at Formation — The General Partner was required to make a contribution to the Partnership at formation, January 1, 2003, of $0.5 million of which TE Products and Louis Dreyfus each contributed one half of the amount to the General Partner. TE Products contributed property, plant, and equipment with a net book value of $67.0 million to the Partnership on January 1, 2003. Additionally, Louis Dreyfus invested $6.1 million for expansion projects for Mont Belvieu that TE Products was required to reimburse if either party terminated the original Development Agreement. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus.

Additional Capital Contributions — Each Partner was required to contribute to the Partnership the Partner's sharing ratio of Discretionary Capital Expenditures. Discretionary Capital Expenditures are expenditures that will enhance the productive capacity of the storage system from its state just prior to the Development Agreement between TE Products and Louis Dreyfus. Louis Dreyfus was required to make the first $5.0 million of Discretionary Capital Expenditures, which Louis Dreyfus met through its $6.1 million investment for expansion projects at Mont Belvieu as discussed above. Thereafter, each Partner contributed equally.

Each quarter, TE Products was required to contribute an amount equal to the actual Mandatory Capital Expenditures for the quarter. Mandatory Capital Expenditures are the capital expenditures related to regulatory compliance, safety, or operational integrity of the Partnership's assets that were originally contributed to the Partnership upon formation or as a result of actions permitted in emergency situations per the Partnership Agreement.

For the two months ended February 28, 2007, TE Products and Louis Dreyfus made no contributions to the Partnership. For the years ended December 31, 2006 and 2005, TE Products contributed $4.8 million and $5.7 million, respectively, and Louis Dreyfus contributed $0.6 million and $0.4 million, respectively, to the Partnership. The 2005 contribution from TE Products includes a combination of a noncash transfer of $1.4 million and cash contributions of $4.3 million.

Loss Sharing — TE Products was required to contribute an amount equal to any loss of the Partnership, unless TE Products' total capital contributions less total distributions was greater than or equal to the maximum loss of $1.0 million. Thereafter, Louis Dreyfus shared equally in losses in excess of $1.0 million.

Income Sharing and Distributions — Each partners' share in the Partnership's earnings was adjusted annually. For the two months ended February 28, 2007 and each of the years ended December 31, 2006 and 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of the Partnership's income before depreciation expense, as defined in the Partnership Agreement. Any amount of the Partnership's annual income before depreciation expense in excess of $6.78 million was allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to the Partnership was allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by the Partnership subsequent to formation was allocated evenly between TE Products and Louis Dreyfus. For the two months ended February 28, 2007 and the years ended December 31, 2006 and 2005, TE

Products', Louis Dreyfus', and the General Partner's sharing ratios in the earnings of the Partnership were 67.7%, 31.6%, and 0.7%, 59.0%, 40.1% and 0.9%, and 64.2%, 35.0% and 0.8%, respectively.

For the two months ended February 28, 2007, the Partnership made no distributions to TE Products and Louis Dreyfus. For the years ended December 31, 2006 and 2005, the Partnership distributed $13.5 million and $12.4 million to TE Products, respectively, and $6.5 million and $5.5 million to Louis Dreyfus, respectively. The 2006 distributions to TE Products include a combination of a noncash transfer of $0.6 million and cash distributions of $12.9 million.

12. SUBSEQUENT EVENTS

On March 1, 2007, TE Products sold its interest in the Partnership and the General Partner to Louis Dreyfus for approximately $137.3 million. In addition, TE Products received a distribution from the Partnership of approximately $10.4 million related to prior earnings. This sale was in compliance with an October 2006 order and consent agreement with the Bureau of Competition of the Federal Trade Commission ("FTC") and was completed in accordance with the terms and conditions approved by the FTC in February 2007.

In accordance with a transition services agreement between TE Products and Louis Dreyfus effective as of March 1, 2007, TE Products will provide certain administrative services to the Partnership for a period of up to two years after the sale, for a fee equal to 110% of the direct costs and expenses TE Products and its affiliates incur to provide the transition services to the Partnership. Payments for these services will be made according to the terms specified in the transition services agreement.

As stated in Note 6, under the terms of the Partnership Agreement, TE Products may store up to four million barrels of product at Mont Belvieu at no cost. In connection with this sale, beginning May 1, 2007 (with respect to propane) and beginning April 1, 2008 (with respect to other products), TE Products' rights to such storage at no cost are terminated. Should TE Products need to use the Partnership's storage facilities for the storage of propane after April 30, 2007 and for the storage of other products after March 31, 2008, it may be required to pay the Partnership the market rate for storage.

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EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Limited Partnership of TEPPCO Partners, L.P. (Filed as Exhibit 3.2 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
3.2	Fourth Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated December 8, 2006 (Filed as Exhibit 3 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on December 13, 2006).
3.3	Amended and Restated Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC (Filed as Exhibit 3 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 10, 2007 and incorporated herein by reference).
3.4	First Amendment to Fourth Amended and Restated Partnership Agreement of TEPPCO Partners, L.P. dated as of December 27, 2007 (Filed as Exhibit 3.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 28, 2007 and incorporated herein by reference).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.1 to the Registration Statement of TEPPCO Partners, L.P. (Commission File No. 33-32203) and incorporated herein by reference).
4.2	Form of Certificate representing Class B Units (Filed as Exhibit 4.3 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
4.3	Form of Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.2 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.4	First Supplemental Indenture between TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as subsidiary guarantors, and First Union National Bank, NA, as trustee, dated as of February 20, 2002 (Filed as Exhibit 99.3 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 20, 2002 and incorporated herein by reference).
4.5	Second Supplemental Indenture, dated as of June 27, 2002, among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, and Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as trustee (Filed as Exhibit 4.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).

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Exhibit Number	Description
4.6	Third Supplemental Indenture among TEPPCO Partners, L.P. as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as trustee, dated as of January 30, 2003 (Filed as Exhibit 4.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
4.7	Full Release of Guarantee dated as of July 31, 2006 by Wachovia Bank, National Association, as trustee, in favor of Jonah Gas Gathering Company (Filed as Exhibit 4.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2006 and incorporated herein by reference).
4.8	Indenture, dated as of May 14, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 99.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 15, 2007 and incorporated herein by reference).
4.9	First Supplemental Indenture, dated as of May 18, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 4.2 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 18, 2007 and incorporated herein by reference).
4.10	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. , Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Filed as Exhibit 4.2 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
4.11	Fourth Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.3 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
4.12	Fourth Amendment to Amended and Restated Credit Agreement and Waiver, dated as of June 29, 2007, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation. (Filed as Exhibit 4.14 to Form 10-Q of TEPPCO Partners, L.P. (Commision File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).

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Exhibit Number	Description
10.1+	Duke Energy Corporation Executive Savings Plan (Filed as Exhibit 10.7 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.2+	Duke Energy Corporation Executive Cash Balance Plan (Filed as Exhibit 10.8 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.3+	Duke Energy Corporation Retirement Benefit Equalization Plan (Filed as Exhibit 10.9 to Form 10-K for TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1999 and incorporated herein by reference).
10.4+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan executed on March 8, 1994 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1994 and incorporated herein by reference).
10.5+	Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan, Amendment 1, effective January 16, 1995 (Filed as Exhibit 10.12 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 1999 and incorporated herein by reference).
10.6+	Form of Employment Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth, John N. Goodpasture, Leonard W. Mallett, Stephen W. Russell, C. Bruce Shaffer, and Barbara A. Carroll (Filed as Exhibit 10.20 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 1998 and incorporated herein by reference).
10.7	Services and Transportation Agreement between TE Products Pipeline Company, Limited Partnership and Fina Oil and Chemical Company, BASF Corporation and BASF Fina Petrochemical Limited Partnership, dated February 9, 1999 (Filed as Exhibit 10.22 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.8	Call Option Agreement, dated February 9, 1999 (Filed as Exhibit 10.23 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1999 and incorporated herein by reference).
10.9+	Form of Employment and Non-Compete Agreement between the Company and J. Michael Cockrell effective January 1, 1999 (Filed as Exhibit 10.29 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.10+	Texas Eastern Products Pipeline Company Non-employee Directors Unit Accumulation Plan, effective April 1, 1999 (Filed as Exhibit 10.30 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.11+	Texas Eastern Products Pipeline Company Non-employee Directors Deferred Compensation Plan, effective November 1, 1999 (Filed as Exhibit 10.31 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.12+	Texas Eastern Products Pipeline Company Phantom Unit Retention Plan, effective August 25, 1999 (Filed as Exhibit 10.32 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 1999 and incorporated herein by reference).
10.13+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Amendment and Restatement, effective January 1, 2000 (Filed as Exhibit 10.28 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).

Exhibit Number	Description
10.14+	TEPPCO Supplemental Benefit Plan, effective April 1, 2000 (Filed as Exhibit 10.29 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2000 and incorporated herein by reference).
10.15	Contribution, Assignment and Amendment Agreement among TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., Texas Eastern Products Pipeline Company, LLC, and TEPPCO GP, Inc., dated July 26, 2001 (Filed as Exhibit 3.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2001 and incorporated herein by reference).
10.16	Certificate of Formation of TEPPCO Colorado, LLC (Filed as Exhibit 3.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 1998 and incorporated herein by reference).
10.17	Unanimous Written Consent of the Board of Directors of TEPPCO GP, Inc. dated February 13, 2002 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2001 and incorporated herein by reference).
10.18	Purchase and Sale Agreement between Burlington Resources Gathering Inc. as Seller and TEPPCO Partners, L.P., as Buyer, dated May 24, 2002 (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of July 2, 2002 and incorporated herein by reference).
10.19	Agreement of Limited Partnership of Val Verde Gas Gathering Company, L.P., dated May 29, 2002 (Filed as Exhibit 10.48 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.20+	Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan, effective June 1, 2002 (Filed as Exhibit 10.49 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2002 and incorporated herein by reference).
10.21+	Amended and Restated TEPPCO Supplemental Benefit Plan, effective November 1, 2002 (Filed as Exhibit 10.44 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.22+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, Second Amendment and Restatement, effective January 1, 2003 (Filed as Exhibit 10.45 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.23+	Amended and Restated Texas Eastern Products Pipeline Company, LLC Management Incentive Compensation Plan, effective January 1, 2003 (Filed as Exhibit 10.46 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.24+	Amended and Restated TEPPCO Retirement Cash Balance Plan, effective January 1, 2002 (Filed as Exhibit 10.47 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.25	Formation Agreement between Panhandle Eastern Pipe Line Company and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, dated as of August 10, 2000 (Filed as Exhibit 10.48 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).

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Exhibit Number	Description
10.26	Amended and Restated Limited Liability Company Agreement of Centennial Pipeline LLC dated as of August 10, 2000 (Filed as Exhibit 10.49 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.27	Guaranty Agreement, dated as of September 27, 2002, between TE Products Pipeline Company, Limited Partnership and Marathon Ashland Petroleum LLC for Note Agreements of Centennial Pipeline LLC (Filed as Exhibit 10.50 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.28	LLC Membership Interest Purchase Agreement By and Between CMS Panhandle Holdings, LLC, As Seller and Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership, Severally as Buyers, dated February 10, 2003 (Filed as Exhibit 10.51 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2002 and incorporated herein by reference).
10.29	Amended and Restated Credit Agreement among TEPPCO Partners, L.P., as Borrower, SunTrust Bank, as Administrative Agent and LC Issuing Bank and The Lenders Party Hereto, as Lenders dated as of October 21, 2004 ($600,000,000 Revolving Facility) (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of October 21, 2004 and incorporated herein by reference).
10.30+	Texas Eastern Products Pipeline Company Amended and Restated Non-employee Directors Deferred Compensation Plan, effective April 1, 2002 (Filed as Exhibit 10.42 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.31+	Texas Eastern Products Pipeline Company Second Amended and Restated Non-employee Directors Unit Accumulation Plan, effective January 1, 2004 (Filed as Exhibit 10.41 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2004 and incorporated herein by reference).
10.32+	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan, dated February 23, 2005, but effective as of January 1, 2005 (Filed as Exhibit 10.4 to Form 10-Q/A of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
10.33	First Amendment to Amended and Restated Credit Agreement, dated as of February 23, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A. as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of February 24, 2005 and incorporated herein by reference).
10.34+	Supplemental Agreement to Employment and Non-Compete Agreement between the Company and J. Michael Cockrell dated as of February 23, 2005 (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.35+	Supplemental Form Agreement to Form of Employment Agreement between the Company and John N. Goodpasture, Stephen W. Russell, C. Bruce Shaffer and Barbara A. Carroll dated as of February 23, 2005 (Filed as Exhibit 10.3 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).

Exhibit Number	Description
10.36+	Supplemental Form Agreement to Form of Employment and Agreement between the Company and Thomas R. Harper, Charles H. Leonard, James C. Ruth and Leonard W. Mallett dated as of February 23, 2005 (Filed as Exhibit 10.4 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2005 and incorporated herein by reference).
10.37+	Amendments to the TEPPCO Retirement Cash Balance Plan and the TEPPCO Supplemental Benefit Plan dated as of May 27, 2005 (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2005 and incorporated herein by reference).
10.38	Second Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2005, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A. and KeyBank, N.A., as Co-Documentation Agents (Filed as Exhibit 99.1 to Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of December 13, 2005 and incorporated herein by reference).
10.39+	Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan Notice of 2006 Award (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2006 and incorporated herein by reference).
10.40+	Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan Notice of 2006 Award (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2006 and incorporated herein by reference).
10.41	Third Amendment to Amended and Restated Credit Agreement, dated as of July 31, 2006, by and among TEPPCO Partners, L.P., the Borrower, several banks and other financial institutions, the Lenders, SunTrust Bank, as the Administrative Agent for the Lenders and as the LC Issuing Bank, Wachovia Bank, National Association, as Syndication Agent, and BNP Paribas, JPMorgan Chase Bank, N.A., and The Royal Bank of Scotland Plc, as Co-Documentation Agents (Filed as Exhibit 10.3 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.42	Amended and Restated Partnership Agreement of Jonah Gas Gathering Company dated as of August 1, 2006 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.43	Contribution Agreement among TEPPCO GP, Inc., TEPPCO Midstream Companies, L.P. and Enterprise Gas Processing, LLC dated as of August 1, 2006 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) dated as of August 3, 2006 and incorporated herein by reference).
10.44	Transaction Agreement by and between TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC dated as of September 5, 2006 (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed September 12, 2006 and incorporated herein by reference).

Exhibit Number	Description
10.45	Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2007, but effective as of February 5, 2007 (Filed as Exhibit 10.18 to Current Report on Form 8-K of Duncan Energy Partners L.P. (Commission File No. 1-33266) filed February 5, 2007 and incorporated herein by reference).
10.46+	Form of Supplemental Agreement to Employment Agreement between Texas Eastern Products Pipeline Company, LLC and assumed by EPCO, Inc., and John N. Goodpasture, Samuel N. Brown and J. Michael Cockrell (Filed as Exhibit 10.62 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2006 and incorporated herein by reference).
10.47+	Form of Retention Agreement (Filed as Exhibit 10.63 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2006 and incorporated herein by reference).
10.48	Second Amended and Restated Agreement of Limited Partnership of TCTM, L.P. by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of February 27, 2007 (Filed as Exhibit 10.65 to Form 10-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the year ended December 31, 2006 and incorporated herein by reference).
10.49	First Amendment to the Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P., EPE Holdings, LLC, TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated February 28, 2007 (Filed as Exhibit 10.8 to Form 10-K of Enterprise Products Partners L.P. (Commission File No. 1-14323) for the year ended December 31, 2006 and incorporated herein by reference).
10.50	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (Filed as Exhibit 99.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 18, 2007 and incorporated herein by reference).
10.51	Company Agreement of TE Products Pipeline Company, LLC by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of June 30, 2007 (Filed as Exhibit 3.2 to the Current Report on Form 8-K of TE Products Pipeline Company, LLC (Commission File No. 1-13603) filed on July 6, 2007 and incorporated herein by reference).
10.52	Company Agreement of TEPPCO Midstream Companies, LLC by and between TEPPCO GP, Inc. and TEPPCO Partners, L.P. dated as of June 30, 2007 (Filed as Exhibit 10.5 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).

Exhibit Number	Description
10.53	Second Amendment to Fourth Amended and Restated Administrative Services Agreement dated August 7, 2007, but effective as of May 7, 2007 (Filed as Exhibit 10.1 to Form 10-Q of Duncan Energy Partners L.P. (Commission File No. 1-33266) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.54	Assignment, Assumption and Amendment No. 2 to Guaranty Agreement, dated as of May 21, 2007, by and among TE Products Pipeline Company, Limited Partnership, Marathon Petroleum Company, LLC and Marathon Oil Corporation (Filed as Exhibit 10.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.55+	Form of TPP Employee Unit Appreciation Right Grant of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.1 to the Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on May 25, 2007 and incorporated herein by reference).
10.56+	Form of TPP Director Unit Appreciation Right Grant of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.8 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2007 and incorporated herein by reference).
10.57+	Form of Phantom Unit Grant for Directors, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. TPP Long-Term Incentive Plan (Filed as Exhibit 10.3 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2007 and incorporated herein by reference).
10.58+	Form of TPP Employee Restricted Unit Grant, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.1 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2007 and incorporated herein by reference).
10.59+	Form of TPP Employee Option Grant, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.2 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2007 and incorporated herein by reference).
10.60	Fifth Amendment to Amended and Restated Credit Agreement, dated as of December 18, 2007, by and among TEPPCO Partners, L.P., the Borrower, the several banks and other financial institutions party thereto and SunTrust Bank, as the administrative agent for the lenders (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 21, 2007 and incorporated herein by reference).
10.61	Term Credit Agreement dated as of December 21, 2007, by and among TEPPCO Partners, L.P., the banks and other financial institutions party thereto and SunTrust Bank, as the administrative agent for the lenders (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed December 28, 2007 and incorporated herein by reference).
10.62	Amended and Restated Guaranty Agreement, dated as of January 17, 2008, by and among The Prudential Insurance Company of America, TCTM, L.P., TEPPCO Midstream Companies, LLC, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed January 24, 2008 and incorporated herein by reference).

Exhibit Number	Description
10.63	Asset Purchase Agreement, dated February 1, 2008, by and among TEPPCO Marine Services, LLC, TEPPCO Partners, L.P., Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (Filed as Exhibit 2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed February 7, 2008 and incorporated herein by reference).
10.64	Transitional Operating Agreement, dated February 1, 2008, by and among TEPPCO Marine Services, LLC, Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed February 7, 2008 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
16	Letter from KPMG LLP to the Securities and Exchange Commission dated April 11, 2006 (Filed as Exhibit 16.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed April 11, 2006 and incorporated herein by reference).
21*	Subsidiaries of TEPPCO Partners, L.P.
23.1*	Consent of Deloitte & Touche LLP – TEPPCO Partners, L.P. and subsidiaries.
23.2*	Consent of Deloitte & Touche LLP – Jonah Gas Gathering Company and subsidiary.
23.3*	Consent of Deloitte & Touche LLP – LDH Energy Mont Belvieu L.P. (formerly Mont Belvieu Storage Partners, L.P.)
23.4*	Consent of KPMG LLP.
24*	Powers of Attorney.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

** Furnished herewith pursuant to Item 601(b)-(32) of Regulation S-K.

\+ A management contract or compensation plan or arrangement.

Exhibit 12.1

Statement of Computation of Ratio of Earnings to Fixed Charges

	2003	2004	2005 (in thousands)	2006	2007
Earnings					
Income From Continuing Operations *	104,958	112,658	138,639	158,538	132,701
Fixed Charges	93,294	80,695	93,414	101,905	119,603
Distributed Income of Equity Investment	28,003	47,213	37,085	63,483	122,900
Capitalized Interest	(5,290)	(4,227)	(6,759)	(10,681)	(11,030)
Total Earnings	220,965	236,339	262,379	313,245	364,174
Fixed Charges					
Interest Expense	84,250	72,053	81,861	86,171	101,223
Capitalized Interest	5,290	4,227	6,759	10,681	11,030
Rental Interest Factor	3,754	4,415	4,794	5,053	7,350
Total Fixed Charges	93,294	80,695	93,414	101,905	119,603
Ratio: Earnings / Fixed Charges	2.37	2.93	2.81	3.07	3.04

* Excludes discontinued operations, gain on sale of assets, provision for taxes and undistributed equity earnings.

Exhibit 21

Subsidiaries of the Partnership

TEPPCO Partners, L.P. (Delaware)

TEPPCO GP, Inc. (Delaware)
TE Products Pipeline Company, LLC (Texas)
TEPPCO Terminals Company, L.P. (Delaware)
TEPPCO Terminaling and Marketing Company, LLC (Delaware)
TEPPCO Colorado, LLC (Delaware)
TEPPCO Midstream Companies, LLC (Texas)
TEPPCO NGL Pipelines, LLC (Delaware)
Chaparral Pipeline Company, LLC (Texas)
Quanah Pipeline Company, LLC (Texas)
Panola Pipeline Company, LLC (Texas)
Dean Pipeline Company, LLC (Texas)
Wilcox Pipeline Company, LLC (Texas)
Val Verde Gas Gathering Company, L.P. (Delaware)
TCTM, L.P. (Delaware)
TEPPCO Crude GP, LLC (Delaware)
TEPPCO Crude Pipeline, LLC (Texas)
TEPPCO Seaway, L.P. (Delaware)
TEPPCO Crude Oil, LLC (Texas)
Lubrication Services, LLC (Texas)
TEPPCO Marine Services, LLC (Delaware)
TEPPCO O/S Port System, LLC (Texas)

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-110207, 333-146108 and 33-81976 on Form S-3, and Registration Statement Nos. 333-143554 and 333-141919 on Form S-8 of our reports dated February 28, 2008, relating to the consolidated financial statements of TEPPCO Partners, L.P. and subsidiaries, and the effectiveness of TEPPCO Partners, L.P. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2008

Exhibit 23.2

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-110207, 333-146108 and 33-81976 on Form S-3, and Registration Statement Nos. 333-143554 and 333-141919 on Form S-8 of our report dated February 28, 2008, relating to the consolidated financial statements of Jonah Gas Gathering Company and subsidiary, appearing in this Annual Report on Form 10-K of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2008

Exhibit 23.3

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-110207, 333-146108 and 33-81976 on Form S-3, and Registration Statement Nos. 333-143554 and 333-141919 on Form S-8 of our report dated February 15, 2008, relating to the financial statements of LDH Energy Mont Belvieu L.P. (formerly Mont Belvieu Storage Partners, L.P.), appearing in this Annual Report on Form 10-K of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Houston, Texas
February 28, 2008

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To Partners of
TEPPCO Partners, L.P.:

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-110207, 333-146108 and 33-81976) and on Form S-8 (No. 333-141919 and 333-143554) of TEPPCO Partners, L.P. and subsidiaries of our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 10, which is as of June 1, 2006, with respect to the consolidated statements of income and comprehensive income, partners' capital and cash flows of TEPPCO Partners, L.P. and subsidiaries for the year ended December 31, 2005, which report appears in the December 31, 2007, annual report on Form 10-K of TEPPCO Partners, L.P. and subsidiaries.

KPMG LLP

Houston, Texas
February 27, 2008

Exhibit 24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned directors and/or officers of TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC (the "Company"), a Delaware limited liability company, acting in its capacity as general partner of TEPPCO Partners, L.P., a Delaware limited partnership (the "Partnership"), does hereby appoint WILLIAM G. MANIAS, his true and lawful attorney and agent to do any and all acts and things, and execute any and all instruments which, with the advice and consent of Counsel, said attorney and agent may deem necessary or advisable to enable the Company and Partnership to comply with the Securities Act of 1934, as amended, and any rules, regulations, and requirements thereof, to sign his name as a director and/or officer of the Company to the Form 10-K Report for the Partnership for the year ended December 31, 2007, and to any instrument or document filed as a part of, or in accordance with, said Form 10-K or amendment thereto; and the undersigned do hereby ratify and confirm all that said attorney and agent shall do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have subscribed these presents this 28th day of February, 2008.

/s/ MICHAEL B. BRACY Michael B. Bracy Director	/s/ MURRAY H. HUTCHISON Murray H. Hutchison Director
/s/ RICHARD S. SNELL Richard S. Snell Director	/s/ JERRY E. THOMPSON Jerry E. Thompson Director
/s/ DONALD H. DAIGLE Donald H. Daigle Director	/s/ WILLIAM G. MANIAS William G. Manias Vice President and Chief Financial Officer

Exhibit 31.1

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended

I, Jerry E. Thompson, certify that:

1. I have reviewed this annual report on Form 10-K of TEPPCO Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2008

/s/ JERRY E. THOMPSON
Jerry E. Thompson
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 31.2

**Certification of Chief Financial Officer pursuant to Rule 13a-14(a) / Rule 15d-14(a),
promulgated under the Securities Exchange Act of 1934, as amended**

I, William G. Manias, certify that:

1. I have reviewed this annual report on Form 10-K of TEPPCO Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 28, 2008

/s/ WILLIAM G. MANIAS
William G. Manias
Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of TEPPCO Partners, L.P. (the "Company") on Form 10-K for the year ended December 31, 2007 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Jerry E. Thompson, President and Chief Executive Officer of Texas Eastern Products Pipeline Company, LLC, the general partner of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JERRY E. THOMPSON

Jerry E. Thompson
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

February 28, 2008

A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of TEPPCO Partners, L.P. (the "Company") on Form 10-K for the year ended December 31, 2007 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, William G. Manias, Vice President and Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC, the general partner of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ WILLIAM G. MANIAS
William G. Manias
Vice President and Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

February 28, 2008

A signed original of this written statement required by Section 906 has been provided to TEPPCO Partners, L.P. and will be retained by TEPPCO Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.