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, 2008
OR
☐ 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	**76-0291058**
(State or Other Jurisdiction of Incorporation or Organization)	**(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. o

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.

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, 2008, the aggregate market value of the registrant's Limited Partner Units held by non-affiliates was $2.6 billion, which was computed using the average of the high and low sales prices of the Limited Partner Units on June 30, 2008.

Limited Partner Units outstanding as of January 31, 2009: 104,696,761.

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,*" the *"Partnership"* or "*TEPPCO*" are intended to mean the business and operations of TEPPCO Partners, L.P. and its consolidated subsidiaries.

References to "*TE Products*," "*TCTM*," "*TEPPCO Midstream*" and *"TEPPCO Marine Services"* mean TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and TEPPCO Marine Services, LLC, our subsidiaries.

References to "*General Partner*" mean Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO.

References to "*TEPPCO GP*" mean TEPPCO GP, Inc., our subsidiary, which is the general partner or manager of TE Products, TCTM and TEPPCO Midstream.

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, the general partner of Enterprise Products Partners L.P.

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.

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 Group Co-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", "outlook" 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, anticipated outcome of various legal and regulatory proceedings, plans, references to future success or events, anticipated market or industry developments, management's outlook for future periods, 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 stability and liquidity of the financial markets, 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; the demand for natural gas is dependent upon the price of natural gas and the locations in which natural gas is drilled; and the demand for marine transportation services is dependent upon the demand for products and prevailing economic conditions. Further, the success of our marine services business is dependent upon, among other things, our ability to effectively assimilate and provide for the operation of that business, maintain key personnel and customer relationships and obtain favorable contract renewals. 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, diversified energy logistics company with operations that span much of the continental United States. Our limited partner units ("Units") are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "TPP". We were formed in March 1990 as a Delaware limited partnership.

We own and operate an extensive network of assets that facilitate the movement, marketing, gathering and storage of various commodities and energy-related products. Our pipeline network is comprised of approximately 12,500 miles of pipelines that gather and transport refined petroleum products, crude oil, natural gas, liquefied petroleum gases ("LPGs") and natural gas liquids ("NGLs"), including one of the largest common carrier pipelines for refined petroleum products and LPGs in the United States. We also own a marine business that transports refined petroleum products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products via tow boats and tank barges. In addition, we own interests in Seaway Crude Pipeline Company ("Seaway"), Centennial Pipeline LLC ("Centennial"), Jonah Gas Gathering Company ("Jonah") and Texas Offshore Port System and an undivided ownership interest in the Basin Pipeline ("Basin"). We operate and report in four business segments:

- pipeline transportation, marketing and storage of refined products, LPGs and petrochemicals ("Downstream Segment");
- gathering, pipeline transportation, marketing and storage of crude oil, distribution of lubrication oils and specialty chemicals and fuel transportation services ("Upstream Segment");
- gathering of natural gas, fractionation of NGLs and pipeline transportation of NGLs ("Midstream Segment"); and
- marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges ("Marine Services 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, and beginning February 1, 2008, through TEPPCO Marine Services. 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 and a 100% membership interest in TEPPCO Marine Services. 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 pipeline 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, natural gas, asphalt, heavy fuel oil and other heated oil products in this Report, 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. 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 17,073,315, or 16.3%, 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"), we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits). Please see Item 13. Certain Relationships and Related Transactions, and Director Independence for additional information.

At December 31, 2008, 2007 and 2006, we had outstanding 104,704,861, 89,911,532 and 89,804,829 Units, respectively.

Business Strategy

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

- § Optimize our existing asset base and realize cost efficiencies through operational and logistical improvements;
- § Continue to invest in fee-based, demand-driven, long-lived internal growth opportunities that increase pipeline system and terminal throughput or expand and upgrade existing assets or operations;
- § Target accretive and complementary acquisitions and expansion opportunities that provide attractive, long-term, balanced growth in each business segment;
- § Manage our business with the financial discipline necessary to maintain our investment grade credit ratings;
- § Share capital costs and risks through joint ventures or other similar arrangements; and
- § Operate in a safe and environmentally responsible manner consistent with applicable regulations.

Please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Overview of Business – Other Considerations" for additional information that impacts our ability to effectively execute our business strategy.

2008 Developments

Acquisitions

On February 1, 2008, we, through our subsidiary, TEPPCO Marine Services, entered the marine transportation business for refined products, crude oil and condensate 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. and Mr. Arlen B. Cenac, Jr., the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. (collectively, "Cenac"), for approximately $444.7 million in cash and newly issued Units. Additionally, we assumed $63.2 million of Cenac's long-term debt. We financed the cash portion of the acquisition consideration and repaid the assumed debt with borrowings under our term credit agreement.

On February 29, 2008, we expanded our Marine Services Segment with the acquisition of marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately-held Houston-based company and an affiliate of Mr. Cenac for $80.8 million in cash. We acquired 7 tow boats, 17 tank barges, rights to two tow boats under construction and certain related commercial and other agreements (or the associated economic benefits). In April 2008, we paid $3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, we paid $3.8 million upon delivery of the second tow boat. We financed the acquisition with borrowings under our term credit agreement.

For additional information, please see "– Marine Services Segment – Barge Transportation of Petroleum Products."

On August 1, 2008, we purchased lubrication and other fuel oil assets, located in Wyoming, from Quality Petroleum, Inc. for approximately $6.8 million. The assets, included in our Upstream Segment, consist of operating inventory, buildings, land and various equipment and the assignment of certain distributor agreements. We funded the purchase through borrowings under our revolving credit facility. For additional information, please see "– Upstream Segment – Gathering, Transportation, Marketing and Storage of Crude Oil."

Organic Growth Projects

During 2008, our organic growth projects included the following:

- § Completion in the third quarter of an extension of the refined products pipeline system in Memphis, Tennessee, to provide for the delivery of jet fuel to the Memphis airport.

- § Completion in the third quarter of a new refined products terminal located in Boligee, Alabama, along the Tennessee-Tombigbee waterway system. The 500,000 barrel storage terminal has capabilities of receiving U.S. Gulf Coast refined products and distributing them via barge or truck.
- § Completion in the third quarter of a 250,000 barrel crude oil storage tank in Cushing, Oklahoma.
- § Continued construction of the multi-year Motiva Enterprises, LLC ("Motiva") project (see "– Downstream Segment – Transportation and Storage of Refined Products, LPGs and Petrochemicals" below).
- § Construction of a new natural gasoline storage tank at our Beaumont terminal with vapor recovery and associated facilities to enable year-round natural gasoline deliveries via new connections to Exxon Mobil Corporation's Beaumont refinery and chemical plants. Completion is expected in the first quarter of 2009.
- § Reactivation of two 400,000 barrel storage tanks related to the 2005 Genco acquisition for distillate storage.
- § Construction of an added extension of our pipeline system in Memphis, Tennessee, to supply a third party refined products distribution terminal. Completion is expected in the second quarter of 2009.

Jonah System Expansions

In June 2008, Jonah completed its Phase V expansion, which increased the combined gathering capacity of our Jonah and Pinedale fields systems from 1.5 Bcf per day to 2.35 Bcf per day. The increased capacity from the expansion has reduced system operating pressures and increased production rates and ultimate reserve recoveries.

In early 2008, Jonah began an expansion of the portion of its system serving the Pinedale field, which is expected to further increase the combined system capacity of our Jonah and Pinedale fields from 2.35 Bcf per day to approximately 2.55 Bcf per day. This project will include an additional 17,000 horsepower of compression at the Paradise and Bird Canyon stations in Sublette County, Wyoming and involve construction of approximately 52 miles of 30-inch and 24-inch diameter pipelines. The pipelines and 10,200 horsepower of compression were completed and placed in service in November 2008. The remaining 6,800 horsepower of compression at Bird Canyon is expected to be completed in mid 2009. The total anticipated cost of this system expansion is expected to be approximately $125.0 million. Our share of the costs of the construction is expected to be 80.64%, and Enterprise Products Partners' share is expected to be 19.36%. Enterprise Products Partners is managing the construction project.

For additional information, please see "– Midstream Segment – Gathering of Natural Gas, Transportation of NGLs and Fractionation of NGLs."

Texas Offshore Port System Joint Venture

In August 2008, we, together with Enterprise Products Partners and Oiltanking Holding Americas, Inc. ("Oiltanking"), formed Texas Offshore Port System, a joint venture to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of total crude oil storage capacity, and (iii) an 85-mile pipeline system that will have the capacity to deliver up to 1.8 million barrels per day of crude oil, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express ("PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas, area. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the acquisition of requisite permits. For additional information, please see "– Upstream Segment – Gathering, Transportation, Marketing and Storage of Crude Oil."

Expansion of Inland Waterway Distribution Network

In August 2008, we commenced operations at our new 500,000 barrel Boligee refined products terminal in Greene County, Alabama. Located along the Tennessee-Tombigbee waterway, the facility provides gasoline, diesel and ethanol storage capabilities and provides for direct access to most U.S. Gulf Coast refining centers through an interconnect with the Colonial pipeline system. Additionally, the intermodal terminal offers truck and marine transportation options and future rail capabilities. The facility also serves as an origination point for refined products delivered to our 130,000 barrel terminal in Aberdeen, Mississippi.

Debt Financings and Retirements

In January 2008, TE Products retired all of its outstanding long-term debt by repaying at maturity $180.0 million principal amount of its 6.45% TE Products Senior Notes due 2008 and redeeming the remaining $175.0 million principal amount of its 7.51% TE Products Senior Notes due 2028. The redemption price for the 7.51% TE Products Senior Notes due 2028 was 103.755% (or $181.6 million, which included a $6.6 million make-whole premium) of the principal amount plus accrued and unpaid interest at January 28, 2008, the date of redemption, of $0.5 million. We funded the retirement of the TE Products debt with borrowings under our term credit agreement.

On March 27, 2008, we issued and sold in an underwritten public offering (i) $250.0 million principal amount of 5.90% Senior Notes due 2013, (ii) $350.0 million principal amount of 6.65% Senior Notes due 2018, and (iii) $400.0 million principal amount of 7.55% Senior Notes due 2038. The proceeds of this offering were used to repay borrowings oustanding under our term credit agreement, which was terminated in March 2008 (see Note 12 in the Notes to Consolidated Financial Statements).

On July 17, 2008, commitments under our revolving credit facility ("Revolving Credit Facility") were increased from $700.0 million to $950.0 million. For further information about our Revolving Credit Facility and availability of commitments thereunder, please refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "– Other Considerations – Credit Facilities."

Equity Offering and Registration Statement

In September 2008, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities and removed from registration securities remaining under our previous universal shelf registration statement.

On September 9, 2008, we issued and sold in an underwritten public offering 9.2 million Units at a price to the public of $29.00 per Unit, including 1.2 million Units sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. The proceeds from the offering, net of underwriting discount and offering expenses, totaled approximately $257.0 million. Concurrently with this offering, we sold 241,380 unregistered Units at the public offering price of $29.00 to TEPPCO Unit L.P. ("TEPPCO Unit"), an affiliate of EPCO in which certain EPCO employees who perform services for us, including certain executive officers, were issued Class B limited partner interests to incentivize them to enhance the long-term value of our Units. The net proceeds from the offering and the unregistered issuance to TEPPCO Unit were used to reduce indebtedness under our Revolving Credit Facility. For additional information regarding TEPPCO Unit and the equity-based compensatory awards issued therein, please see Note 4 in the Notes to Consolidated Financial Statements.

Financial Information by Business Segment

The following is a discussion of the business and properties of our four business segments. See Note 14 in the Notes to Consolidated Financial Statements for financial information by segment.

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 two refined products terminals, one in Aberdeen, Mississippi and another in Boligee, Alabama;
- § 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. 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 one 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.

Through TTMC, we conduct distribution and marketing operations whereby we provide terminaling services at our Aberdeen and Boligee terminals. The Aberdeen terminal, 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. In August 2008, we commenced operations at a 500,000 barrel refined products terminal in Boligee in Greene County, Alabama.

Located along the Tennessee-Tombigbee waterway system, the facility provides gasoline, diesel and ethanol storage capabilities and provides for direct access to most U.S. Gulf Coast refining centers through an interconnect with the Colonial pipeline system. Additionally, the intermodal terminal offers truck and marine transportation options and future rail capabilities. The facility also serves as an origination point for refined products delivered to our Aberdeen terminal.

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, 2008:

	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, 2008, 2007 and 2006, were as follows:

	For Year Ended December 31,		
	2008	**2007**	**2006**
Refined Products Deliveries: (1)			
Gasoline	88.9	96.3	94.9
Jet Fuels	23.2	25.7	25.5
Distillates (2)	47.5	53.0	44.9
Subtotal	159.6	175.0	165.3
LPGs Deliveries:			
Propane (3)	30.0	31.8	36.5
Butanes (includes isobutane)	8.9	10.1	8.5
Subtotal	38.9	41.9	45.0
Petrochemical Deliveries (4)	40.6	43.9	32.5
Total Product Deliveries	239.1	260.8	242.8
Centennial Product Deliveries	41.0	55.6	44.8

(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 and 10.0 million for the years ended December 31, 2007 and 2006, respectively, related to a pipeline that was sold on March 1, 2007 to Louis Dreyfus Energy Services L.P. ("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. Major origination facilities for this 20-inch system are in Baytown, Texas, Beaumont, Texas, and Mont Belvieu, Texas. 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.

In December 2006, we signed an agreement with 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 or July 1, 2010, whichever comes first. 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. 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 one of the primary origination facilities 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 $355.0 million, which includes $25.0 million for the 11-mile, 20-inch pipeline, $24.0 million of capitalized interest and $17.0 million of mutually agreed upon scope changes requested by Motiva. Through December 31, 2008, we have spent approximately $170.1 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.

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. The Centennial pipeline loops the Products Pipeline System between Beaumont, Texas and southern Illinois. Looping the Products Pipeline System permits effective supply of product to points south of Illinois as well as incremental product supply capacity to mid-continent markets downstream of southern Illinois. Marathon operates the mainline Centennial pipeline, and TE Products operates the Beaumont origination point and the Creal Springs terminal.

Through December 31, 2008, 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 gasoline during the spring and summer driving seasons, although recent high gasoline prices have moderated this trend to a certain extent. 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 partner at our Aberdeen and Boligee terminals. We also purchase refined products from our throughput partner and establish a margin by selling refined products for physical delivery through spot sales and contract sales. These marketing activities are conducted at our Aberdeen and Boligee truck racks to independent wholesalers and retailers of refined products. Spot 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, 2008, 2007 and 2006, were as follows:

	For Year Ended December 31,		
	2008	2007	2006
Refined Products Deliveries:			
Central (1)	83.8	84.3	74.6
Midwest (2)	56.2	66.6	66.6
Ohio and Kentucky	19.6	24.1	24.1
Subtotal	159.6	175.0	165.3
LPGs Deliveries:			
Central, Midwest and Kentucky (1)(2)	20.6	22.1	28.5
Ohio and Northeast (3)	18.3	19.8	16.5
Subtotal	38.9	41.9	45.0
Petrochemical Deliveries (4)	40.6	43.9	32.5
Total Product Deliveries	239.1	260.8	242.8
Centennial Product Deliveries	41.0	55.6	44.8

(1) Arkansas, Louisiana, Missouri, Alabama 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.

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 feedstock 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 polymer grade 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, 2008, 2007 and 2006, our Downstream Segment had approximately 172, 130 and 125 customers, respectively. During the years ended December 31, 2008, 2007 and 2006, total revenues attributable to the top 10 customers (and percentage of total segment revenues) were $138.1 million (37%), $155.5 million (43%) and $143.5 million (47%), respectively. During each of the three years ended December 31, 2008, 2007 and 2006, no single customer accounted for more than 10% of total Downstream Segment revenues. During each of the three years ended December 31, 2008, 2007 and 2006, 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 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;
- our 50% equity investment in Seaway;
- our 33.3% equity investment in Texas Offshore Port System; and
- our 13% undivided joint interest in Basin Pipeline.

Properties and Operations

Our Upstream Segment gathers, transports, markets and stores crude oil, distributes lubrication oils and specialty chemicals and provides fuel transportation services, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Our Upstream Segment uses its asset base to aggregate crude oil and provides 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. TCO also ships on Seaway, in which we have an ownership interest.

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, 2008, 2007 and 2006, were as follows (in millions):

	For Year Ended December 31,		
	2008	2007	2006
Barrels Delivered:			
Crude oil transportation	114.3	96.5	91.5
Crude oil marketing	254.7	232.0	222.1
Crude oil terminaling	166.8	135.0	126.0
Lubrication Services:			
Lubricants and chemicals (total gallons)	21.9	15.3	14.4
Fuel transported (total gallons)	43.4	--	--
Seaway Barrels Delivered:			
Long-haul	76.2	49.4	88.4
Short-haul	205.1	229.5	223.4

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, 2008:

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	19 tanks with 3,100,000 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 which has the ability to deliver crude oil to Cushing.

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"). Seaway also has a connection to our South Texas system that allows it 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, 2008, 2007 and 2006, we received distributions from Seaway of $13.8 million, $12.4 million and $20.5 million, respectively.

Texas Offshore Port System Joint Venture

In August 2008, we, together with Enterprise Products Partners and Oiltanking formed Texas Offshore Port System, a joint venture to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of total crude oil storage capacity, and (iii) an 85-mile pipeline system that will have the capacity to deliver up to 1.8 million barrels per day of crude oil, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express ("PACE"), will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the acquisition of requisite permits.

We, Enterprise Products Partners and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. A subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and an affiliate of Enterprise Products Partners have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. At December 31, 2008, we have invested $36.0 million in this joint venture.

The joint venture is part of our strategic plan for growing the Partnership. Demand for the project is being driven by planned and expected refinery expansions along the U.S. Gulf Coast, expected increased shipping traffic and operating limitations of regional ship channels. Further, the joint venture complements our 5.4 million barrel refined products storage facility currently under construction in Port Arthur to support the expansion of Motiva's nearby refinery, which is expected to double its existing capacity in 2010.

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. A pumpover occurs when the last title transfer is executed and the physical barrels are delivered out of TCPL's custody to the ultimate owner. TCPL owns and operates storage facilities primarily in Midland and Cushing with a storage capacity of approximately 4.1 million barrels to facilitate the terminaling business.

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

On August 1, 2008, we purchased lubrication and other fuel oil assets, located in Wyoming, from Quality Petroleum, Inc. for approximately $6.8 million, which includes $1.3 million related to a non-compete agreement. The assets, included in our Upstream Segment, consist of operating inventory, buildings, land and various equipment and the assignment of certain distributor agreements. Through its subsidiary, QP-LS, LLC, LSI provides fuel transportation services to customers.

Customers

Our customers for the sale, transportation, storage and terminaling 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. LSI also provides fuel transportation services to customers primarily in Wyoming.

Gross sales revenue of the Upstream Segment attributable to the top 10 customers (and percentage of total segment gross sales revenue) was $13.0 billion (96%), $8.1 billion (84%) and $7.4 billion (75%) for the years ended December 31, 2008, 2007 and 2006, respectively. For the year ended December 31, 2008, Valero Energy Corp. ("Valero"), BP Oil Supply Company and Shell Trading Company accounted for 22%, 17% and 14%, respectively, 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 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, 2008, Valero, BP Oil Supply Company and Shell Trading Company accounted for 21%, 16%, and 13%, respectively, of TEPPCO's total consolidated revenues. 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.

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 transportation charges, 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 strong competition for supplies of crude oil at the wellhead, and declines in domestic crude oil production have intensified this competition. The most significant competitors in the crude oil gathering and marketing business include other crude oil pipeline companies, major integrated oil companies and their marketing affiliates, financial institutions with trading platforms and independent gatherers and marketers. Competition is based primarily on quality of customer service, competitive pricing and proximity to refiners and other marketing hubs.

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. ("Val Verde"), which gathers and treats coal bed methane natural gas;
§ 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 settled in-kind 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, 2008, 2007 and 2006, is presented below:

	For Year Ended December 31,		
	2008	**2007**	**2006**
Gathering – Natural Gas – Jonah (Bcf) (1)	709.9	587.4	473.9
Gathering – Natural Gas – Val Verde (Bcf)	166.9	175.7	181.9
Transportation – NGLs (MMBbls)	73.6	77.0	69.7
Fractionation – NGLs (MMBbls)	4.2	4.2	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. The table includes Jonah's gathering volumes for the full years ended December 31, 2008, 2007 and 2006.

Jonah Gas Gathering Joint Venture

The majority of the growth in the Midstream Segment is due to our expansions of the Jonah system, which is located in the Green River Basin in southwestern Wyoming. Since our acquisition of Jonah in 2001, the system has been expanded in five phases, increasing system capacity from approximately 450 MMcf/d to approximately 2.35 Bcf per day.

In August 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 system serving the Jonah and Pinedale fields. Enterprise Products Partners serves as operator of Jonah. 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 the Audit, Conflicts and Governance Committee of the Board of Directors of our General Partner ("ACG Committee").

In February 2006, Enterprise Products Partners assumed 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 cost previously advanced. 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 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, beginning in August 2007, our ownership interest in Jonah was approximately 80.64%, and Enterprise Products Partners' ownership interest in Jonah was approximately 19.36%. Amounts exceeding an agreed upon base cost estimate for the expansion of $415.2 million were shared 19.36% by Enterprise Products Partners and 80.64% by us. Our ownership interest in Jonah is currently anticipated to remain at 80.64%.

In early 2008, Jonah began an expansion of the portion of its system serving the Pinedale field, which is expected to increase the combined capacity of the system serving the Jonah and Pinedale fields from 2.35 Bcf per day to approximately 2.55 Bcf per day. This project will include an additional 17,000 horsepower of compression at the Paradise and Bird Canyon stations in Sublette County, Wyoming and involve construction of approximately 52 miles of 30-inch and 24-inch diameter pipelines. The pipelines and 10,200 horsepower of compression were completed and placed in service in November 2008. The remaining 6,800 horsepower of compression at Bird Canyon is expected to be completed in mid 2009. The total anticipated cost of this system expansion is expected to be approximately $125.0 million. Our share of the costs of the construction is expected to be 80.64%, and Enterprise Products Partners' share is expected to be 19.36%. Enterprise Products Partners is managing this construction project.

Jonah Gas Gathering System Business. The Jonah system serves the Jonah and Pinedale fields in Wyoming, which, according to the Energy Information Administration's ("EIA") 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, Questar's mainline pipeline and access to the Rockies Express Pipeline via Questar Overthrust. At the end of 2008, the Jonah system consists of approximately 714 miles of pipelines ranging in size from three inches to 36 inches in diameter, five compressor stations with an aggregate of approximately 273,800 horsepower and related metering facilities. Gas gathered on the Jonah system is collected from approximately 2,021 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. The four top producers are under life-of-lease contracts that represent approximately 96% of the volumes of the system in 2008. 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 fee. Jonah does not generally take title to the natural gas gathered with the exception of inventory imbalances settled in-kind 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 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 an amine treating facility. The Val Verde gathering system is capable of gathering and treating approximately 550 million cubic feet of gas per day. The Val Verde system delivers gas to El Paso Natural Gas Company and Transwestern Pipeline Company, two interstate pipeline systems serving the western United States.

The Val Verde system gathers coal bed methane ("CBM") from the Fruitland Coal Formation of the San Juan Basin in New Mexico and Colorado and some conventional natural gas for the producers. 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 have gathering rates that escalate annually. Under these contracts, Val Verde gathers the natural gas supplied to its gathering systems, treats the natural gas 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 been in decline, and are expected to continue 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 multi-year agreement to transport and treat natural gas through this connection. Val Verde transported an average of 155 MMcf/d from this interconnection in 2008.

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, 2008, is set forth in the following table:

NGL Pipeline	Physical Capacity (barrels/day)	Description
Chaparral (1) (2)	118,000	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)	65,000	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 (3)	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.

(2) See discussion in "Chaparral Open Season" below.

(3) The Panola Pipeline, San Jacinto Pipeline and the southern portion of the Dean Pipeline transport NGLs for major integrated oil and gas companies, including Enterprise Products Partners (see "Customers" below) at posted tariffs and under negotiated lease and exchange agreements. The Panola Pipeline and San Jacinto Pipeline originate at an East Texas Plant Complex in Panola County, Texas. The southern portion of the Dean Pipeline originates in South Texas and delivers NGLs into a customer's pipeline at Point Comfort, Texas.

Chaparral Open Season. In February 2008, Chaparral announced the start of a binding "open season" process to seek shipper support for a proposed expansion of its pipeline. The open season was successfully concluded in June 2008 with the commitment from shippers for a 15-year term at a transportation rate that we believe is sufficient to justify the capital expenditures necessary to expand the Chaparral pipeline capacity. The project is designed to increase annual average system capacity by approximately 15,000 barrels per day. The expansion, which is anticipated to cost approximately $10.0 million and to be completed in the second half of 2009, involves upgrading certain pipe sections, and includes installing additional pumping capability at existing pump stations.

Fractionation. TEPPCO Colorado has two NGL fractionation facilities, located in northeast Colorado, which separate NGLs into individual components. TEPPCO Colorado is currently supported by a fractionation agreement with DCP Midstream Partners, L.P. ("DCP") through 2018. Based upon contract terms, fractionation revenues are recognized based upon the volume of NGLs fractionated at a fixed rate per gallon. 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

Typically, our natural gas gathering systems experience higher throughput rates during the summer months, when natural gas-fired power generation facilities increase output to meet residential and commercial demand for electricity for air conditioning and in the winter months, when natural gas is needed as fuel for residential and commercial heating. Additionally, at Jonah, new well connections have historically been subject to seasonal constraints as a result of winter range restrictions in the Pinedale field. Producers in the Pinedale field were prohibited from drilling activities typically during November through April due to wildlife restrictions, and accordingly we were limited in our ability to connect new wells to the system during that time. During 2008, the majority of these restrictions were lifted, and as such, the producers in the Pinedale field have fewer drilling restrictions.

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, 2008, the Midstream Segment had approximately 58 customers. Revenue attributable to the top 10 customers (and percentage of total segment revenues) was $105.8 million (86%) for the year ended December 31, 2008, of which DCP and its affiliates, ConocoPhillips (and its subsidiary, Burlington Resources Inc.), and Enterprise Products Partners and its affiliates accounted for approximately 20%, 20% and 11%, respectively.

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.

During each of the three years ended December 31, 2008, 2007 and 2006, 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 Services Segment – Barge Transportation of Petroleum Products

We conduct business in our Marine Services Segment through TEPPCO Marine Services, which:

§ transports refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges;
§ provides offshore flow-back operations relating to well-testing and pipeline remediation activities. We service refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, the Intracoastal Waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system; and
§ gathers crude oil from production facilities and platforms along the U.S. Gulf Coast and in the Gulf of Mexico.

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 that comprised the marine transportation business of Cenac Towing Co., Inc. ("Cenac Towing"), 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"). On February 29, 2008, we expanded our Marine Services Segment with the acquisition of marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately-held Houston-based company and an affiliate of Mr. Cenac. We acquired 7 tow boats, 17 tank barges, rights to two tow boats under construction and certain related commercial and other agreements (or the associated economic benefits). One of the tow boats under construction was delivered to us in April 2008 and the second in June 2008.

In connection with our entry in the marine transportation business, we entered into a transitional operating agreement with Cenac for a period of up to two years from the date of the Cenac acquisition. Cenac operates our Marine Services Segment through their marine and shore-based support employees. Under the transitional operating agreement, we reimburse Cenac for personnel salaries and related employee benefit expenses and certain repairs and maintenance expenses on our equipment, as well as payment of a monthly service fee.

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. Barge transportation is more fuel efficient and produces fewer emissions than similar movements by truck or rail and also reduces road and rail congestion. The capacity of one barge is equivalent to 15 railcars or 60 trucks; one gallon of fuel moves one ton of cargo 576 miles on the inland waterways, 413 miles on rail, and 155 miles on truck; and barge transportation produces 40% less air emissions than truck and 16% less air emission than rail for cargo movements (ton-miles).

The marine transportation industry uses tow boats as power sources and tank 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, as of December 31, 2008, in our marine transportation business and certain operating statistics for the Marine Services Segment:

Class of Equipment	Number in Class	Capacity (bbl)/ Horsepower (hp)
Inland:		
Barges (includes seven single hull barges)	16	< 25,000 bbl
Barges	89	> 25,000 bbl
Tow boats	22	< 2,000 hp
Tow boats	23	> 2,000 hp
Offshore:		
Barges (includes three single hull barges)	8	> 20,000 bbl
Tow boats	3	< 2,000 hp
Tow boats	3	> 2,000 hp

Fleet available days (1)	51,932
Fleet operating days (2)	48,308
Fleet utilization (3)	93%

(1) Equal to the number of calendar days from our acquisition of Cenac on February 1, 2008 and Horizon on February 29, 2008 through December 31, 2008 multiplied by the total number of vessels less the aggregate number of days that our vessels are not operating due to scheduled maintenance and repairs or unscheduled instances where vessels may have to be drydocked in the event of accidents and other unforeseen damage.
(2) Equal to the number of our fleet available days from our acquisition of Cenac on February 1, 2008 and Horizon on February 29, 2008 through December 31, 2008 less the aggregate number of days that our vessels are off-hire.
(3) Equal to the number of fleet operating days divided by the number of fleet available days during the period.

Our transportation services are generally provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement. Most of the inland term contracts have one-year terms with the remainder having terms of up to two years. Substantially all of the inland contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. Most of the offshore service and transportation contracts have up to one-year terms with renewal options, which are exercisable subject to agreement on rates applicable to the option terms, or are spot contracts. A spot contract is an agreement with a customer to move cargo within designated operating areas for a rate negotiated at the time the cargo movement takes place.

As is typical for inland and offshore affreightment contracts, the term contracts establish set 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. The costs of fuel, substantially all of which is a passthrough expense, and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts. We are responsible for the remaining operating costs, including equipment maintenance costs, various inspection costs, the cost of maintaining insurance coverage on the vessels under these contracts, and other operating costs under certain of our contracts that do not contain such reimbursement or escalation provisions. We do not assume ownership of the products we transport in this segment.

Since our acquisition of Cenac and Horizon through the end of the third quarter of 2008, as the customer contracts became subject to periodic renewal, we obtained renewals of substantially all contracts at increased day rates. During the fourth quarter of 2008, there were five inland customer affreightment contracts that were not renewed due to general economic conditions. The marine vessels impacted by these non-renewals will be employed in the spot market until we can secure term contracts. As a result, our fleet utilization may be reduced during 2009 compared to 2008 levels. As overall demand for refined products has declined some softening of the transportation market is expected. Additionally, as the customer contracts become subject to periodic renewal during 2009, we expect to renew them at day rates generally consistent with the current economic refined products and crude oil market dynamics.

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 certain 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 and TEPPCO Marine Services belong 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 our contracts contain provisions regarding AWO membership and RCP compliance. The RCP has been recognized by many groups, including the USCG and shipper organizations. We are periodically audited by an AWO-certified auditor to verify compliance.

EPCO maintains insurance coverage on marine operations on our behalf, although insurance will not cover many types of hazards that might occur, including certain environmental accidents, and if covered we may still have responsibility for any applicable deductibles. Our marine insurance program covers our hulls and certain liabilities which may arise from vessel operations.

Vessel Management, Crewing and Employees

Cenac maintains an experienced work force of marine and shore-based personnel. As of December 31, 2008, approximately 451 of Cenac's employees provide services to TEPPCO Marine Services 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.

Cenac's shore-based 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 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. 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. Demand for asphalt is generally seasonal, with higher volumes typically transported during months when weather allows for efficient road construction. Weather events, such as hurricanes and tropical storms entering in the U.S. Gulf of Mexico, can adversely impact both the offshore and inland businesses. Cold weather and ice can negatively impact the inland operations on the upper Mississippi and Illinois rivers. Our offshore marine vessels support pipeline cleanout operations which typically are performed during the summer months.

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 U.S. Gulf Coast.

At December 31, 2008, our Marine Services Segment had approximately 42 customers. Revenues attributable to the top 10 customers (and percentage of total segment revenues) was $130.9 million (80%) for the year ended December 31, 2008, of which Valero, Plains Marketing L.P. and Shell and affiliates accounted for 28%, 16% and 13%, respectively. During the year ended December 31, 2008, no single customer of the Marine Services Segment accounted for more than 10% of TEPPCO's total consolidated revenues.

Competition

Our marine transportation business competes 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, positions 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.

We also believe we can offer a competitive advantage over our competitors due to the lower age of our fleet of marine vessels compared to the industry average. The average age of our fleet is 12 years versus an industry average of 22 years. However, several of our competitors have announced their intention to increase their tank barge fleets. We currently believe demand within the inland marine transportation industry will absorb the additional capacity being built, but additional new construction could create an oversupply of capacity within the industry.

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 $300.5 million for the year ended December 31, 2008. 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, 2008 (in millions):

	Revenue Generating	Sustaining Existing Operations	System Upgrades	Capitalized Interest	Total
Downstream Segment	$ 162.6	$ 29.0	$ 6.5	$ 11.7	$ 209.8
Midstream Segment	1.2	3.5	0.5	0.1	5.3
Upstream Segment	11.5	17.2	3.6	1.0	33.3
Marine Services Segment	42.4	0.6	0.2	0.4	43.6
Other	0.2	8.2	0.1	--	8.5
Total	$ 217.9	$ 58.5	$ 10.9	$ 13.2	$ 300.5

Revenue generating capital spending by the Downstream Segment totaled $162.6 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 $1.2 million and was used primarily to increase capacity of the Panola Pipeline. Revenue generating capital spending by the Upstream Segment totaled $11.5 million and was used primarily for the expansion of our facilities and pipeline connections in West Texas and Cushing, Oklahoma. Revenue generating capital spending by the Marine Services Segment totaled $42.4 million and was used primarily for the construction and acquisition of additional tow boats and tank barges. In order to sustain existing operations, we spent $29.0 million for various Downstream Segment pipeline projects, $3.5 million for the Midstream Segment, $17.2 million for Upstream Segment facilities, $0.6 million for the Marine Services Segment and $8.2 million for our allocated share of EPCO spending related to various assets, including vehicles, computer equipment and software that benefit all of our business segments. An additional $10.9 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 2009 will be approximately $340.0 million (including approximately $17.0 million of capitalized interest). Excluding capitalized interest, we expect to spend approximately $270.0 million for revenue generating projects, which includes $170.0 million for our expected spending on the Motiva project. We expect to spend approximately $49.0 million to sustain existing operations (including $16.0 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 $4.0 million to improve operational efficiencies and reduce costs among all of our business segments.

Additionally, we expect to invest approximately $27.0 million in our Jonah joint venture during 2009 for the completion of additional facilities to expand the Pinedale field production. We invested approximately $129.8 million in our Jonah joint venture during 2008. We expect to invest approximately $70.0 million in 2009 as our net contribution to our Texas Offshore Port System joint venture. We invested approximately $36.0 million during 2008 in our Texas Offshore Port System joint venture.

During 2009, 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, joint venture distributions, debt or the issuance of additional equity, and the possible disposition of assets.

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 and terms of service be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates or rules and authorizes the FERC to investigate such changes 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 and rules that are already in effect and may order a carrier to change them prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deems just and reasonable (*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 limits 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. FERC has interpreted the Energy Policy Act to require a demonstration of a substantial change in the overall rate of return of a pipeline, not simply a single cost element, in order for a “grandfathered” rate to no longer be deemed just and reasonable. The U.S Court of Appeals for the D.C. Circuit upheld this interpretation in 2007.

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.

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, our revenues might be adversely affected by changes in the FERC's ratemaking policies.

In May 2005, the FERC issued a "Policy Statement on Income Tax Allowances" ("Policy Statement"), 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. In December 2005, the FERC issued its "Order on Initial Decision and on Certain Remanded Cost Issues" in various dockets involving another pipeline (the "December 2005 Order"). Among other things, the December 2005 Order applied the Policy Statement to the specific facts of a case involving another pipeline, suggesting how the FERC will treat other Master Limited Partnership ("MLP") petroleum pipelines. The December 2005 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. The D.C. Circuit Court of Appeals fully upheld FERC's new tax allowance policy and the application of that policy in the December 2005 Order.

In April 2008, the FERC issued a Policy Statement in which it declared that it would permit MLPs to be included in rate of return proxy groups for determining rates for services by natural gas and oil pipelines. It also addressed the application to limited partnership pipelines of the FERC's discounted cash flow methodology for determining rates of return on equity. The FERC applied the new policy to several ongoing proceedings involving other pipelines. The FERC's income tax allowance and rate of return policies remain subject to change.

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 USCG, 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.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to climate change. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and 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 specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs, including those that may be used in our operations. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our operations, results of operations and cash flows.

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, 2008, we have an accrued liability of $6.9 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 our 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 USCG and ABS 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 tow boats 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 tow boats 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 tow boats 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 June 2008, DOT extended its pipeline safety regulations, including Integrity Management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around "unusually sensitive areas." 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, 2008, there were approximately 2,400 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 1,400 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. In addition to EPCO employees performing services for us, approximately 451 of Cenac's employees provide services to TEPPCO Marine Services under the transitional operating agreement.

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

The current challenges in the financial markets may adversely impact on our business and financial condition.

The current challenges in the financial markets have had, and may continue to have, an impact on our business and our financial condition. We may face significant challenges if these conditions do not improve. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet our capital commitments and flexibility to react to changing economic and business conditions. The cost of equity capital has become substantially more expensive, and the distribution yields on new equity that we may issue, if any, may be substantially higher than historical levels.

Our business depends on activity and expenditure levels in the energy industry, which are directly correlated to energy prices. In addition to the bankruptcy of Lehman Brothers ("Lehman"), which is the parent company of one of the lenders under our Revolving Credit Facility, the credit crisis could have a negative impact on our remaining lenders or our customers, causing them to fail to meet their obligations to us. Many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. New credit facilities and other debt financing from institutional sources have generally become more difficult and expensive to obtain, and there may be a general reduction in the amount of credit available in the markets in which we conduct business. Additionally, many of our customers' equity values have substantially declined. The combination of a reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' spending. For example, a number of our customers have announced reduced capital expenditure budgets for 2009.

Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

We may not be able to fully execute our business strategy if we encounter illiquid capital markets or other difficulties in acquisitions and expansions.

Our business strategy contemplates targeting accretive and complementary acquisitions and expansion opportunities that provide attractive long-term, balanced growth in each of our business segments. We regularly consider and enter into discussions regarding strategic transactions that we believe will present opportunities to pursue our strategy.

Acquisitions and expansions may require substantial capital or the incurrence of substantial indebtedness, and any limitations on our access to capital will impair our ability to execute this component of our strategy. If the costs of such capital becomes too expensive, our ability to develop or acquire assets that result in an increase in the cash generated from operations per Unit will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates and underwriting discounts. Our prospects and ability to increase distributions may also be limited if we are unable to make accretive acquisitions because we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, or if we are outbid by competitors.

Even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per Unit. 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. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Increases in interest rates could increase our borrowing costs, adversely impact our Unit price and our ability to issue additional equity, which could have an adverse effect on our cash flows and our ability to fund our operations.

Due to the recent volatility and decline in the credit markets, the interest rate on our Revolving Credit Facility could increase, which would reduce our cash flows. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, the market price for our Units will be affected by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our Units, and a rising interest rate environment could have an adverse effect on our Unit price and our ability to issue additional equity in order to make acquisitions, to reduce debt or for other purposes.

Our future debt level, downgrades of our debt ratings by credit agencies or a reduction of credit granted by our counterparties may limit our future financial and operating flexibility.

At December 31, 2008, we had outstanding approximately (i) $2.5 billion of consolidated senior debt, consisting of $516.7 million of borrowings under our Revolving Credit Facility and $1.7 billion principal amount of senior notes, and (ii) $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 contains 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 (generally defined in our partnership agreement as consolidated cash receipts less consolidated cash disbursements and cash reserves established by our General Partner), incur certain liens, engage in specified transactions with affiliates and complete mergers, acquisitions and sales of assets. The facility also prevents 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, to terminate all commitments to extend further credit. Although our Revolving Credit Facility restricts our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial.

In addition to prevailing market conditions, which are susceptible to volatility and decline, our ability to access capital markets on acceptable terms could be affected by our debt level, generally, current maturities and the amount of our debt maturing in the next several years. Moreover, if the rating agencies were to downgrade our credit ratings, our borrowing costs would increase, and we may also experience difficulty accessing capital markets and receiving open lines of trade credit from our counterparties. 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 acceptable terms at the time a debt obligation becomes due in the future, we may be unable to fund such an obligation, which would constitute a default, or we may be forced to refinance the obligation through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we may 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 levels.

A downgrade of our credit ratings could result in our being required to post financial collateral up to the amount of our guaranty of indebtedness of our Centennial joint venture, which was $65.0 million at December 31, 2008. Further, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities and crude oil marketing business that require the posting of financial collateral, which may be substantial, if our credit were to be downgraded below investment grade.

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, including the price of and demand for oil, natural gas and other products we transport, store and market;
§ 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 weather in our operating areas;
§ 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.

Our profitability depends on demand for and production levels of the products we gather, transport, market and store in the markets we serve.

Declines in crude oil or natural gas production or in the demand for the petroleum products we gather, transport, market and store adversely affect our business. Declines in crude oil or natural gas production may result from a number of factors, including:

§ natural declines from depleting wells,
§ decreased exploration and production activities or lower successful drilling activity in our service areas, including as a result of reduced capital budgets of producers,
§ decreased or volatile oil and natural prices,
§ general economic factors, including recessions and other adverse economic conditions,
§ adverse weather and other natural phenomena,
§ actions by foreign nations,

- § government regulations, including drilling and related permits, alternative fuel requirements and conservation measures, and
- § industry changes, including the effect of consolidations and divestitures and technological advances.

We cannot influence or control the production of crude oil we transport or the development of natural gas in the fields we serve. Oil and natural gas prices, which have declined substantially since reaching record levels in mid-2008, play a principal role in the decisions of producers. Even if new oil or natural gas reserves were discovered in areas that we serve, producers may choose not to develop those reserves or may transport or gather them using different systems.

Decreased crude oil production, as well as decreased demand from crude oil refineries or their suppliers, results in lower volumes on our Upstream segment crude oil pipelines and lower associated revenues. In addition, to maintain the volumes of crude oil we purchase in connection with our marketing business, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines or volumes lost to competitors. Replacement of lost volumes of crude oil is especially difficult when production levels are generally low, which intensifies competition to gather available production.

Our Midstream Segment 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.

With respect to our Downstream and Marine Services Segments, market demand and our revenues from these businesses can be adversely affected by the factors described above with respect to crude oil and natural gas, but demand can also vary based upon the different end uses of the products we transport, market or store. For example:

- § demand for gasoline depends upon market price, prevailing economic conditions, demographic changes in the markets we serve and availability of gasoline produced in refineries located in these markets;
- § demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities that use distillates as a substitute and usage for agricultural operations;
- § demand for jet fuel depends on prevailing economic conditions and military usage; and
- § propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred and will likely continue to occur.

Our Texas Offshore Port System joint venture is subject to various business, operational and regulatory risks and may not be successful.

The Texas Offshore Port System joint venture is expected to represent an important component of our Upstream Segment, requiring an estimated $600.0 million in capital contributions from us through 2011. We and each of the other joint venture partners own a one-third interest in the joint venture, and a subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. Accordingly, we will not have full control over the ongoing operational decisions. If we were unable to make a required capital contribution in Texas Offshore Port System, whether due to our inability to access capital markets or otherwise, our interest could be diluted, and we could suffer other adverse consequences. Further, if we or one of our joint venture partners were unable to make required contributions, the other partners may need to raise and contribute capital above their estimated share in order to complete the project, which capital may not be accessible on economical terms.

A variety of factors outside our control, such as weather, natural disasters, the fluctuating costs of steel and other raw materials and difficulties or inabilities in obtaining rights-of-way, permits or other regulatory approvals, as well as performance by third-party contractors, may result in increased costs or delays in construction. The offshore terminal will require approval by the USCG and issuance of a Deepwater Port License, while the onshore pipeline and storage facilities will be subject to review by the EPA, Army Corps of Engineers and DOT. Some of these factors are critical to the initiation or completion of significant phases of the project, and may involve time consuming processes. For example, we do not expect to commence significant construction activities on portions of the project until the Deepwater Port License is obtained. The joint venture is also subject to various hazards inherent in the construction and operation of an offshore crude oil port and pipeline system, including damage to the ports, pipelines and related facilities caused by hurricanes and other inclement weather, inadvertent damage from third parties, leaks, operator error, litigation, environmental pollution and risk related to operating in a marine environment. Cost overruns, construction delays or other hazards inherent in the construction and operation of such a facility, whatever the cause, could have a material adverse effect on the success of the our joint venture project or on our business, results of operations, financial condition and prospects.

Our marine transportation business is substantially dependent upon Cenac and subject to liabilities from its operation of our vessels.

We depend on Cenac and its personnel to operate our marine vessels under a transitional operating agreement entered into in connection with the February 2008 acquisition for up to two years from the acquisition. The success of this business is largely dependent on maintaining adequate, licensed crew for our tow boats. 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. 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.

The U.S. inland waterway infrastructure is aging and may result in increased costs and disruptions to our Marine Services Segment.

Maintenance of the U.S. inland waterway system is vital to our Marine Services Segment's operations. The system is composed of over 12,000 miles of commercially navigable waterway, supported by over 240 locks and dams designed to provide flood control, maintain pool levels of water in certain areas of the country and facilitate navigation on the inland river system. The U.S. inland waterway infrastructure is aging, with more than half of the locks over 50 years old. As a result, due to the age of the locks, scheduled and unscheduled maintenance outages may be more frequent in nature, resulting in delays and additional operating expenses. Failure of the federal government to adequately fund infrastructure maintenance and improvements in the future would have a negative impact on our ability to provide transportation services for our customers on a timely basis. In addition, any additional user taxes that may be imposed in the future to fund infrastructure improvements would increase our operating expenses.

Our Marine Services Segment could be adversely impacted by a marine accident or spill.

A marine accident or spill event, caused by us or another inland marine transportation company, could close a portion of the inland waterway system for an extended period of time preventing any movements of our marine vessels into or out of the inland waterway river system.

Our Marine Services Segment could be adversely impacted by the construction of inland tank barges by its competitors.

Several of our competitors have announced their intention to increase their tank barge fleets. Additional new construction could create an oversupply of capacity within the industry, which would adversely impact our fleet utilization and results of operation.

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

The construction of new energy logistics assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

- we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;
- we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;
- we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;
- the completion or success of our project may depend on the completion of a project that we do not control, such as a refinery, that may be subject to numerous of its own potential risks, delays and complexities; and
- we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

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

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 ICA, as amended, the Energy Policy Act and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under the ICA, 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. The FERC also can order reparations for overcharges effective two years prior to the date of a complaint. 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, or challenges to our application of that methodology, 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.

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, our revenues might be adversely affected by changes in the FERC's ratemaking policies. For example, there are several ongoing proceedings involving other pipelines in which the FERC is refining its policies regarding income tax allowances and rate of return.

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 December 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 ("D.C. Circuit"). The D.C. Circuit denied these appeals in May 2007 and fully upheld FERC's new tax allowance policy and the application of that policy in the December 2005 order.

In December 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. This and other proceedings pertaining to the FERC's income tax allowance policy remain pending.

In April 2008, the FERC issued a Policy Statement in which it declared that it would permit MLPs to be included in rate of return proxy groups for determining rates for services by natural gas and oil pipelines. It also addressed the application to limited partnership pipelines of the FERC's discounted cash flow methodology for determining rates of return on equity. The FERC applied the new policy to several ongoing proceedings involving other pipelines. The FERC's rate of return policy remains subject to change.

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 as well as rates of return, particularly with respect to pipelines organized as partnerships. If any of our rates were to be calculated using cost of service rate methodologies in the future, the outcome of these ongoing proceedings could adversely affect our revenues.

Competition could adversely affect our operating results.

We face substantial competition in our transportation, gathering and marketing activities. Some of our competitors have capital resources many times greater than ours or access to or control of greater supplies of hydrocarbons and related products.

Our refined products, LPG, NGL and marine transportation businesses compete with other pipelines and marine transportation companies in the areas they serve, as well as with trucks and railroads in some of those areas. Substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

Our crude oil transportation, gathering and marketing business competes with common carriers and proprietary pipelines owned and operated by major integrated oil companies, large independent pipeline companies and other companies in the areas where our pipelines deliver products, independent gatherers and marketers and financial institutions with trading platforms. The crude oil gathering and marketing business can be characterized by thin margins and strong competition for supplies of crude oil at the wellhead, and declines in domestic crude oil production have intensified competition in this line of our business.

Third party shippers generally do not have long-term contractual commitments to ship crude oil or refined products on our pipelines. Accordingly, shippers have the ability to elect to transport volumes on competitors' pipelines or by alternative means, which would reduce the volumes on our pipelines and associated revenues.

Our natural gas gathering business competes with major integrated oil companies and independent gas gatherers in seeking new supplies of natural gas for its systems. Alternate gathering facilities are available to the producers we serve, and producers may also elect to construct proprietary gathering systems.

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. Further, adverse economic conditions, such as the credit crisis that developed in the fourth quarter of 2008, increase the risk of nonpayment and nonperformance by customers, particularly for customers that are smaller companies. 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, net out agreements 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, 2008, 2007 and 2006, Valero accounted for 21%, 16% and 14%, respectively, of our total consolidated revenues, and for the years ended December 31, 2008, 2007 and 2006, BP Oil Supply Company accounted for 16%, 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, 2008, 2007 and 2006.

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.

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 prospects, 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. 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 operation of the joint venture, which could require additional capital contributions by us and Enterprise Products Partners or diminish expected benefits from the joint venture. Any of these factors could materially and adversely affect our results of operations, financial condition and prospects.

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 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. Adverse economic conditions, such as the financial crisis that developed in the fourth quarter of 2008, increase the risks of nonpayment or nonperformance by our hedging counterparties. See Note 6 in the Notes to Consolidated Financial Statements for a discussion of our financial instruments.

Our pipeline integrity program and periodic tank maintenance requirements 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.

In June 2008, DOT issued a Final Rule extending its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around “unusually sensitive areas.” The issuance of these new gathering and low-stress pipeline safety regulations, including requirements for integrity management of those pipelines, is likely to increase the operating costs of our pipelines subject to such new requirements.

The American Petroleum Institute Standard 653 (“API 653”) is an industry standard for the inspection, repair, alteration and reconstruction of existing storage tanks. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Periodic tank maintenance requirements 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 storage tanks.

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 Services Segment, 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 and operations 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, such as regulations designed to reduce the emission of greenhouse gases, 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 USCG, the DOT, 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 ABS. The USCG and the National Transportation Safety Board set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards. The USCG 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 services 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.

We are 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. For example, 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.

Our marine services business would be adversely affected if the U.S. government purchases or requisitions any of our vessels under the Merchant Marine Act.

The Merchant Marine Act of 1936 is a federal law that provides that the U.S. Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If any of our vessel are purchased or requisitioned for an extended period of time by the U.S. government, such transactions could have a material adverse affect on our results of operations, cash flow, and could reduce 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 onshore and marine 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 and marine operations on our behalf, although insurance will not cover many types of hazards that might occur, including certain environmental accidents, and if covered we may still have responsibility for any applicable deductibles. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, changes in the insurance markets resulting from the hurricanes of 2005 and 2008 have made it more difficult for us to obtain certain types of coverage. The recent global financial crisis may negatively impact insurance carriers and affect our ability to obtain 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 services and personnel of EPCO, which is controlled by Dan L. Duncan.

Other than certain operational personnel for our Marine Services Segment, all of our management, administrative and operating functions are performed by employees of EPCO pursuant to the ASA. 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 and other senior operational personnel who run our business are employees of EPCO. These officers and personnel have many years of relevant business experience, and future unplanned departures could have a material adverse effect on our business, financial condition and results of operations. None of our officers are parties to employment agreements with EPCO or our General Partner.

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.

The credit crisis and related instability in the global financial system may drive our customers and competitors to pursue mergers or other business combinations. Such transactions 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 Mr. Duncan, including our Jonah and Texas Offshore Port System joint ventures. 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 or affiliates 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 a 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 non-executive 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 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 ACG Committee 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 an MLP. 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

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 Internal Revenue Service ("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 regarding our treatment as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our 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 taxation. Our Partnership Agreement currently provides that if we become subject to taxation as a corporation or otherwise subject to entity-level taxation as a result of the enactment of new legislation or a change in the interpretation of existing law by a government taxing authority, the minimum quarterly distribution amount and the target distribution level will be adjusted to reflect the impact of the additional taxes upon us.

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 an 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. 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.

Because we cannot match transferors and transferees of Units, we must maintain uniformity of the economic and tax characteristics of our Units to a purchaser of Units. We take depreciation and amortization positions that are intended to maintain such uniformity. These depreciation and amortization positions may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from 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.

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.

We prorate our items of income, gain, loss, and deduction between transferors and transferees of our Units each month based upon the ownership of our Units on the first day of each month, instead of on the basis of the date a particular Unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss, and deduction between transferors and transferees of our Units each month based upon the ownership of our Units on the first day of each month, instead of on the basis of the date a particular Unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

A unitholder whose Units are loaned to a "short seller" to cover a short sale of Units may be considered as having disposed of those Units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those Units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose Units are loaned to a "short seller" to cover a short sale of Units may be considered as having disposed of the loaned Units, the unitholder may no longer be treated for tax purposes as a partner with respect to those Units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those Units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those Units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their Units.

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 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.

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, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Dakota, Tennessee, 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.

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

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 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 at that time, 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. Pre-trail discovery in this proceeding is underway. 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.

In 1999, our Arcadia, Louisiana, facility and adjacent terminals were directed by the Remediation Services Division of the Louisiana Department of Environmental Quality ("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, 2008, we have an accrued liability of $0.5 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.

We received a notice of probable violation from the DOT 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.

In October 2005, 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 failed to conform to quality specifications of the Interconnect and Operator Balancing Agreement ("Interconnect Agreement") which has allegedly caused damages to the Opal Plant in excess of $28.0 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 system to the Opal Plant, in violation of the Interconnect Agreement. Jonah denies any liability to Williams. Discovery is ongoing.

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 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, 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 2008 and 2007, respectively, as reported on the NYSE, were as follows:

	2008		2007	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 39.86	$ 32.91	$ 44.53	$ 39.88
Second	36.88	32.50	46.20	42.15
Third	34.02	24.97	46.01	37.04
Fourth	30.09	16.90	40.81	37.17

Based on the information received from our transfer agent, as of February 2, 2009, there were approximately 1,258 unitholders of record of our Units.

The quarterly cash distributions on our Units for the years ended December 31, 2008 and 2007, were as follows:

Record Date	**Payment Date**	**Amount Per Unit**
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
April 30, 2008	May 7, 2008	0.710
July 31, 2008	August 7, 2008	0.710
October 31, 2008	November 6, 2008	0.725
January 30, 2009	February 6, 2009	0.725

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. 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 MLP 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

There were no sales of unregistered securities in 2008 other than as previously reported in the 2007 Form 10-K and our Current Report on Form 8-K filed on September 9, 2008.

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

In November 2008, 1,000 of our restricted unit awards vested and were converted into Units, of which 384 of these Units were sold back to us by the employee to cover related withholding tax requirements. The average price paid per Unit was $24.33. For additional information regarding outstanding equity awards, please refer to Note 4 in the Notes to Consolidated Financial Statements and Item 11. Executive Compensation.

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,				
	2008	2007	2006	2005	2004
	(in thousands, except per Unit amounts)				
Income Statement Data:					
Operating revenues:					
Sales of petroleum products	$ 12,840,649	$ 9,147,104	$ 9,080,516	$ 8,061,808	$ 5,426,832
Transportation – Refined products	164,120	170,231	152,552	144,552	148,166
Transportation – LPGs	105,419	101,076	89,315	96,297	87,050
Transportation – Crude oil	57,305	45,952	38,822	37,614	37,177
Transportation – NGLs	52,192	46,542	43,838	43,915	41,204
Transportation – Marine	164,265	--	--	--	--
Gathering – Natural gas	57,097	61,634	123,933	152,797	140,122
Other revenues	91,842	85,521	78,509	68,051	67,539
Total operating revenues	13,532,889	9,658,060	9,607,485	8,605,034	5,948,090
Purchases of petroleum products	12,703,534	9,017,109	8,967,062	7,986,438	5,367,027
Operating expenses (1)	408,240	271,167	278,448	255,359	257,372
General and administrative expenses	41,364	33,657	31,348	33,143	28,016
Depreciation and amortization	126,329	105,225	108,252	110,729	112,284
(Gains) losses on sales of assets	2	(18,653)	(7,404)	(668)	(1,053)
Operating income	253,420	249,555	229,779	220,033	184,444
Interest expense – net	(139,988)	(101,223)	(86,171)	(81,861)	(72,053)
Gain on sale of ownership interest in MB Storage	--	59,628	--	--	--
Equity earnings	82,693	68,755	36,761	20,094	22,148
Other income – net (including interest income)	2,044	3,022	2,965	1,135	1,320
Income before provision for income taxes	198,169	279,737	183,334	159,401	135,859
Provision for income taxes	4,617	557	652	--	--
Income from continuing operations	193,552	279,180	182,682	159,401	135,859
Discontinued operations (2)	--	--	19,369	3,150	2,689
Net income	$ 193,552	$ 279,180	$ 202,051	$ 162,551	$ 138,548
Basic and diluted income per Unit: (3)					
Continuing operations	$ 1.65	$ 2.60	$ 1.77	$ 1.67	$ 1.53
Discontinued operations (2)	--	--	0.19	0.04	0.03
Net income per Unit	$ 1.65	$ 2.60	$ 1.96	$ 1.71	$ 1.56

	December 31,				
	2008	2007	2006	2005	2004
	(in thousands)				
Balance Sheet Data:					
Property, plant and equipment – net	$ 2,439,910	$ 1,793,634	$ 1,642,095	$ 1,960,068	$ 1,703,702
Total assets	5,049,820	4,750,057	3,922,092	3,680,538	3,186,284
short-term debt	--	353,976	--	--	--
long-term debt	2,529,519	1,511,083	1,603,287	1,525,021	1,480,226
Partners' capital	1,591,479	1,264,627	1,320,330	1,201,370	1,011,103

	For Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in thousands, except per Unit amounts)				
Cash Flow Data:					
Net cash provided by continuing operating activities (2)	$ 346,861	$ 350,572	$ 271,552	$ 250,723	$ 263,896
Net cash provided by operating activities	346,861	350,572	273,073	254,505	267,167
Capital expenditures to sustain existing operations (4)	(58,487)	(52,149)	(39,966)	(40,783)	(41,733)
Capital expenditures	(300,503)	(228,272)	(170,046)	(220,553)	(156,749)
Net cash used in continuing investing activities	(831,020)	(317,400)	(273,716)	(350,915)	(182,759)
Net cash used in investing activities	(831,020)	(317,400)	(273,716)	(350,915)	(190,157)
Net cash provided by (used in) financing activities	484,164	(33,219)	594	80,107	(90,057)
Distributions paid	(327,997)	(294,450)	(278,566)	(251,101)	(233,057)
Distributions paid per Unit (3)	$ 2.84	$ 2.74	$ 2.70	$ 2.68	$ 2.64

(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 the following Unit issuances: 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. In 2008, 14,793,329 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, facilities and marine vessels that we own or operate while meeting the regulations that govern the operation of our assets and the costs associated with such regulations. We operate and report in four business segments:

- § Our Downstream Segment, which is engaged in the pipeline 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, distribution of lubrication oils and specialty chemicals and fuel transportation services;
- § Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and pipeline transportation of NGLs; and
- § Our Marine Services Segment, which is engaged in the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges.

As part of our business strategy, we engage from time to time in discussions with potential sellers and strategic partners regarding the possible purchase of assets, pursuit of joint ventures or other expansion opportunities that complement our principal lines of business. These potential expansion opportunities consist of both smaller transactions, as well as larger transactions that could have a material impact on our capital structure and operating results. We cannot predict the likelihood of completing, or the timing of, any such transactions.

Downstream Segment

Our Downstream Segment revenues are earned from pipeline transportation, marketing and storage of refined products and LPGs, intrastate pipeline 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. Transportation revenues are recognized as products are delivered to customers. Storage revenue is generated from fees based on storage volumes contracted for by customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Refined products terminaling revenue is generated from fees charged for receiving refined products into the terminal and delivering them out of the terminal. Refined products terminaling revenues are recognized as products are out-loaded. From time to time, we buy and sell products to balance our inventory for operational needs, and the 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 partner and establishing a margin by selling refined products for physical delivery through spot and contract sales. These marketing activities are conducted at our Aberdeen and Boligee truck racks to independent wholesalers and retailers of refined products. Spot purchases and sales are generally contracted to occur on the same day.

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, has accounted for approximately 56% of the Downstream Segment's refined products transportation revenues in the three year period ended December 31, 2008, 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 had 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 has accounted for approximately 30% of the Downstream Segment's refined products transportation revenues in the three year period ended December 31, 2008, 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 has accounted for approximately 15% of the Downstream Segment's refined products revenues in the three year period ended December 31, 2008, 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. Both sustained rising prices and a severe decline in the general economy will reduce demand for refined products, with the health of the general economy having the greatest impact. While refined product prices declined sharply in 2008 after rising steadily, the overall economy has a greater influence on demand. High market price of propane could result in the use of alternative fuel sources and tend to reduce volumes typically associated with the summer and early fall fill of consumer storage of propane. Also, sustained higher market prices generally affect butanes and petrochemicals in a manner similar to the refined products and LPGs discussed above. 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, although recent high gasoline prices have moderated this trend. 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, pipeline transporting, marketing and storing crude oil, distributing lubrication oils and specialty chemicals, and fuel transportation services principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Our customers pay us fees based on volume of crude oil gathered, transported, and stored; through the sale of crude oil based upon contract or index rates per barrel; through the distribution of lubrication oils and specialty chemicals based upon a mark-up per gallon; and based upon fuel transported per truck load. Marketing operations consist primarily of aggregating crude oil purchased at the lease along our pipeline systems, and 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. Gathering and transportation revenues are recognized as crude oil are delivered to customers. Storage revenue is recognized upon the receipt of crude oil into storage and upon performance of storage services. Marketing revenues are accrued at the time title to the crude oil sold transfers to the purchaser, which typically occurs upon receipt of the crude oil by the purchaser. Revenues are also earned from trade documentation and terminaling services, primarily at Cushing, Oklahoma, and Midland, Texas and are recognized as services are completed. These revenues are generated from customers by charging a fee for receiving crude oil into the terminal and delivering it out of the terminal.

Our Upstream Segment also includes our equity investments in Seaway and Texas Offshore Port System (see Note 9 in the Notes to Consolidated Financial Statements). The Seaway system 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. Seaway also has a connection to our South Texas system that allows it to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing. Texas Offshore Port System, a joint venture between us and affiliates of Enterprise Products Partners and Oiltanking, was formed to design, construct, operate and own a new Texas offshore crude oil port and pipeline system.

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 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. In addition, certain of our pipeline tariffs include a pipeline loss allowance (“PLA”) whereby the shipper gives us physical product in addition to a cash tariff payment. This PLA is in exchange for our bearing the risk of pipeline volumetric losses. The value of these PLA barrels is based on the current market value at the time the barrels are transported and recorded to inventory. When these PLA barrels are sold, we recognize gains or losses in revenue depending on the current market price of the product at the date of sale.

During periods when supply exceeds the demand for crude oil in the near term, the market for crude oil is often in “contango,” meaning that the price of crude oil for future deliveries is higher than current prices. A contango market generally has a negative impact on our gathering and transportation activities, but is favorable to our terminaling and storage activities. Those who control storage at major trading hubs (such as the Cushing) can simultaneously purchase production at current prices for storage and sell forward at higher prices for future delivery.

When there is a higher demand than supply of crude oil in the near term, the market is "backwardated," meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on our gathering and transportation activities because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil as current prices are above delivery prices in the futures markets.

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on our Upstream Segment. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our marketing business.

Midstream Segment

Our Midstream Segment revenues are earned from the gathering of conventional natural gas and coal bed methane, pipeline transportation of NGLs and fractionation of NGLs. Under our gathering agreements, we gather the natural gas supplied to our systems and redeliver the natural gas for a fixed fee. Gathering revenues are recognized as natural gas is received from the customer. Transportation revenues are recognized as NGLs are delivered. Based upon contract terms, fractionation revenues are recognized based upon the volume of NGLs fractionated at a fixed rate per gallon. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of natural gas imbalances that are settled in-kind. Since we record natural gas imbalances using average market prices, the results of our Midstream Segment are affected by changes in the prices of natural gas. Coal bed methane volumes gathered on the Val Verde system have been in decline, and are expected to continue to decline, primarily due to the natural decline of production by producers in the field.

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 fee. In addition to gathering natural gas, Jonah also purchases gas at the wellhead and sells gas and condensate. The purchases and sales generally occur within the same month to minimize price risk. 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 year ended December 31, 2006.

Other than the effects of normal operating pressure fluctuations or pressure reductions due to system expansions, we can neither influence nor control the operation, development or production levels of the gas fields served by the Jonah and Val Verde systems.

Marine Services Segment

Our Marine Services Segment revenues are earned from inland and offshore transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. We generate revenues by charging customer for the transportation and distribution of their products utilizing our marine vessels at set daily rates or current market rates. Revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which are generally less than ten days in duration. We also provide offshore flow-back operations relating to well-testing and pipeline remediation. We utilize our offshore tugs in general towing operations. Demand for our marine transportation services is generally driven by demand for refined products, crude oil and other hydrocarbon-based products in the areas in which we operate.

Our transportation services are generally provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement. Most of the inland term contracts have one-year terms with the remainder having terms of up to two years. Substantially all of the inland contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. Most of the offshore service and transportation contracts have up to one-year terms with renewal options, which are exercisable subject to agreement on rates applicable to the option terms, or are spot contracts. A spot contract is an agreement with a customer to move cargo within designated operating areas for a rate negotiated at the time the cargo movement takes place. We do not assume ownership of the products we transport in this segment. As is typical for inland and offshore affreightment contracts, the term contracts establish set 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. The costs of fuel and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts. We are responsible for the remaining operating costs, such as equipment maintenance costs, various inspection costs, the cost of maintaining insurance coverage on the vessels under these contracts, and for other operating costs under our other contracts that do not contain such reimbursement or escalation provisions.

General Outlook for 2009

The current global recession and financial crisis have, among other effects, reduced demand for hydrocarbon products, which in turn has generally led to volatility and a significant decrease in the prices for crude oil, natural gas and NGLs. For example, the average U.S. retail price of regular conventional gasoline ranged from $4.03 per gallon in mid-2008 to $1.81 per gallon in January 2009 according to the EIA; the price of West Texas Intermediate crude oil ranged from a high near $147 per barrel in mid-2008 to $35 per barrel in January 2009; while the price of natural gas at the Henry Hub ranged from a high of over $13.00 per MMBtu in mid-2008 to approximately $5.00 per MMBtu in January 2009. On a composite basis, the price of NGLs declined from $1.68 per gallon for the third quarter of 2008 to $0.74 per gallon in the fourth quarter of 2008.

This significant decrease in commodity prices has caused many oil and gas producers, including many of our customers, to reduce their capital expenditures and budgets in 2009. This has resulted in a substantial reduction in the number of drilling rigs operating in the United States. According to a survey by Baker Hughes Incorporated, the U.S. operating rig count has decreased from a peak of 2,031 rigs in September 2008 to approximately 1,590 in January 2009. We expect producers in our operating areas to reduce their drilling activity and that an overall decrease in the volume of products for which we provide transportation, storage, marketing and other services likely will occur as a result of the downturn.

Similarly, gasoline demand declined approximately 3.5% for the year 2008 relative to 2007, according to EIA statistics. Demand for diesel fuel was also down in January 2009 due to the slowing economy requiring less transportation of goods to market and airlines reducing flights, impacting jet fuel deliveries. Until the U.S. economy begins to come out of the recession, we expect demand for these refined products to remain at decreased levels.

The financial crisis and associated factors have also led to the effective insolvency, liquidation or government intervention for a number of financial institutions, investment companies, hedge funds and highly leveraged industrial companies and to significant volatility and declines in the prices of debt and equity securities generally. For example, the S&P 500 and Dow Jones Industrial Average suffered losses of approximately 38% and 34%, respectively, in 2008. Likewise, the major index for publicly traded partnerships, the Alerian MLP Index, declined approximately 42% in 2008. Contraction in credit available to and investor redemptions for certain investment companies and hedge funds exacerbated the selling pressure and volatility in both the debt and equity markets. These factors have resulted in a significantly higher cost of debt and equity capital for the public and private sector. Further, demand for equity securities through secondary offerings, including our Units, may be reduced due to investor redemptions at and lack of credit available to certain investment companies and hedge funds that significantly participated in equity offerings by publicly-traded partnerships over the past few years.

Our actions to raise approximately $510 million of capital in the third quarter of 2008, including $264 million of net proceeds from a September 2008 equity offering and $250 million from increasing commitments under our Revolving Credit Facility, put TEPPCO in a good position to avoid the higher cost of debt and equity capital that have prevailed in the fourth quarter of 2008 and early 2009. These actions have enhanced our liquidity and financial flexibility to fund our cash needs for our operating and investment activities in 2009. Our disciplined approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under our Revolving Credit Facility, should provide us with a foundation to meet our anticipated liquidity and capital resource requirements. We currently believe that, should the need arise, we would be able to access the capital markets in 2009 to maintain financial flexibility. We believe our size, business position, financial ratios and investment grade credit ratings facilitate our ability to access the capital markets.

Our 2009 capital program will focus on the completion of the refined products terminal we are building at Port Arthur, Texas as well as investments for our portion of the Texas Offshore Port System joint venture. Total construction costs for the Port Arthur refined products terminal are expected to be approximately $330.0 million. Through December 31, 2008, we have spent approximately $170.1 million on this construction project. Our agreement with Motiva provides for a 15-year throughput and dedication of volume, which will commence upon completion of the refinery expansion or July 1, 2010, whichever comes first. The total construction costs for the Texas Offshore Port System joint venture are estimated at approximately $1.8 billion, or approximately $600.0 million for our share. Total construction costs incurred in 2008 were approximately $90.0 million, or approximately $30.0 million for our share. The remaining capital costs associated with this project are expected to be incurred over the next three years. Spending for this project could be delayed if there are delays in Texas Offshore Port System receiving its deepwater port license from federal authorities.

We anticipate that 2009 may be a challenging year, but should nevertheless provide us with some opportunities as well. Many refiners have announced plans to perform their major maintenance projects in the first quarter 2009, which will limit supply of products in early 2009. To the extent that mid-continent refineries come off line for maintenance, we expect that would improve the demand for products supplied from the U.S. Gulf Coast and would be a positive for us. Our Upstream Segment is benefiting from the current crude oil contango market, which generates demand for our storage services, especially at our 3.1 million barrels of storage facilities in Cushing. In addition to storage leasing revenue, we benefit from additional fees on volumes moving in and out of these storage facilities.

In addition to our Port Arthur project and Texas Offshore Port System joint venture, we have other growth opportunities available to us that we may pursue, including: expanding our South and West Texas crude oil systems in our Upstream Segment; adding new volumes to our Val Verde system through an existing connection accessing Fruitland Coal production from the Colorado San Juan Basin; expanding our Downstream Segment system delivery capability of refined products to our Midwest markets; and providing LPGs service in our Marine Services Segment with a pressurized chemical barge which is currently under construction.

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, equity method investments, 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, 2008, approximately 5% 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 $1.5 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, 2008, approximately 1% 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 $0.1 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

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. None of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized. A variance of 10% in our aggregate estimate for environmental costs would have an approximate $0.7 million impact on annual earnings. For information concerning environmental regulation and environmental costs and contingencies, see Items 1 and 2. Business and Properties, “Regulation – Environmental and Safety Matters.”

At December 31, 2008 and 2007, our accrued liabilities for environmental remediation projects totaled $6.9 million and $4.0 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in actual cash required to remediate contamination for which we are responsible.

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.

Examples of such 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, 2008 and 2007, the net book value of our property, plant and equipment was $2,439.9 million and $1,793.6 million, respectively. We recorded $96.3 million, $81.1 million and $78.9 million in depreciation expense during the years ended December 31, 2008, 2007 and 2006, respectively.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that 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.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flow expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

Measuring the Fair Value of Goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the fourth quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

- § discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;
- § long-term growth rates for cash flows beyond the discrete forecast period; and
- § appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2008 and 2007, the carrying value of our goodwill was $106.6 million and $15.5 million, respectively. We have not recorded any goodwill impairment charges for any of the periods presented.

Amortization Methods and Estimated Useful Lives of Intangible Assets

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

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under natural gas transportation contracts on our Val Verde system or the fractionation agreement on TEPPCO Colorado. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

- § the expected useful life of the related tangible assets (e.g., pipeline or other asset, etc.);
- § any legal or regulatory developments that would impact such contractual rights; and
- § any contractual provisions that enable us to renew or extend such agreements.

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

At December 31, 2008 and 2007, we had $113.8 million and $132.3 million of intangible assets, net of accumulated amortization, respectively, related to natural gas transportation contracts for our Val Verde system. 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. The value of these 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 $2.0 million impact on annual amortization expense. Changes in the estimated remaining production will impact the timing of amortization expense reported for future periods.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with business combinations and asset purchases. The value we assigned to these customer relationships is being amortized to earnings on a straight-line basis over the expected period of economic benefit. Customer relationship intangible assets represent the economic value attributable to certain relationships 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. Additionally, we have non-compete agreement intangible assets which we entered into in connection with business combinations or asset purchases that are being amortized to earnings on a straight-line basis over the life of the respective agreement.

Additionally, we have $40.7 million of excess investments, net of accumulated amortization, at December 31, 2008, 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. We are amortizing the $12.6 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 $0.5 million impact on annual earnings.

Results of Operations

The following table summarizes financial information by business segment for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	For Year Ended December 31,		
	2008	2007	2006
Operating revenues:			
Downstream Segment	$ 372,964	$ 362,691	$ 304,301
Upstream Segment	12,873,426	9,173,683	9,109,629
Midstream Segment (1)	122,417	122,235	201,269
Marine Services Segment	164,274	--	--
Intersegment eliminations	(192)	(549)	(7,714)
Total operating revenues	13,532,889	9,658,060	9,607,485
Operating income:			
Downstream Segment	91,270	135,055	91,262
Upstream Segment	95,683	84,222	70,840
Midstream Segment (1)	27,559	25,767	65,499
Marine Services Segment	34,507	--	--
Intersegment eliminations	4,401	4,511	2,178
Total operating income	253,420	249,555	229,779
Equity earnings (losses):			
Downstream Segment	(14,603)	(12,396)	(8,018)
Upstream Segment	11,693	2,602	11,905
Midstream Segment (1)	90,004	83,060	35,052
Intersegment eliminations	(4,401)	(4,511)	(2,178)
Total equity earnings	82,693	68,755	36,761
Earnings before interest: (2)			
Downstream Segment	77,526	184,251	84,746
Upstream Segment	108,164	87,246	83,540
Midstream Segment (1)	117,947	109,463	101,219
Marine Services Segment	34,520	--	--
Interest expense	(159,158)	(112,253)	(96,852)
Interest capitalized	19,170	11,030	10,681
Income before provision for income taxes	198,169	279,737	183,334
Provision for income taxes	4,617	557	652
Income from continuing operations	193,552	279,180	182,682
Discontinued operations	--	--	19,369
Net income	$ 193,552	$ 279,180	$ 202,051

(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, 2008, 2007 and 2006 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2008	2007	2006	2008-2007	2007-2006
Operating revenues:					
Sales of petroleum products	$ 37,554	$ 30,326	$ 5,800	$ 7,228	$ 24,526
Transportation – Refined products	164,120	170,231	152,552	(6,111)	17,679
Transportation – LPGs	105,419	101,076	89,315	4,343	11,761
Other	65,871	61,058	56,634	4,813	4,424
Total operating revenues	372,964	362,691	304,301	10,273	58,390
Costs and expenses:					
Purchases of petroleum products	37,194	30,041	5,526	7,153	24,515
Operating expense	133,090	103,406	106,455	29,684	(3,049)
Operating fuel and power	40,536	39,906	38,354	630	1,552
General and administrative	16,501	16,929	17,085	(428)	(156)
Depreciation and amortization	43,063	46,141	41,405	(3,078)	4,736
Taxes – other than income taxes	11,312	9,866	8,437	1,446	1,429
Gains on sales of assets	(2)	(18,653)	(4,223)	18,651	(14,430)
Total costs and expenses	281,694	227,636	213,039	54,058	14,597
Operating income	91,270	135,055	91,262	(43,785)	43,793
Gain on sale of ownership interest in MB Storage	--	59,628	--	(59,628)	59,628
Equity losses	(14,603)	(12,396)	(8,018)	(2,207)	(4,378)
Interest income	643	879	1,008	(236)	(129)
Other income	216	1,085	494	(869)	591
Earnings before interest	$ 77,526	$ 184,251	$ 84,746	$ (106,725)	$ 99,505

The following table presents volumes delivered in barrels and average tariff per barrel for the years ended December 31, 2008, 2007 and 2006 (in thousands, except tariff information):

	For Year Ended December 31,			Percentage Increase (Decrease)	
	2008	2007	2006	2008-2007	2007-2006
Volumes Delivered:					
Refined products	159,586	174,910	165,269	(9%)	6%
LPGs	38,802	40,875	44,997	(5%)	(9%)
Total	198,388	215,785	210,266	(8%)	3%
Average Tariff per Barrel:					
Refined products	$ 1.03	$ 0.97	$ 0.92	6%	5%
LPGs	2.72	2.47	1.98	10%	25%
Average system tariff per barrel	$ 1.36	$ 1.25	$ 1.15	9%	9%

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Sales and purchases related to petroleum products marketing activities at our Aberdeen and Boligee terminals increased $7.2 million each for the year ended December 31, 2008, compared with the year ended December 31, 2007. The increases in purchases and sales were primarily a result of the start-up of the Boligee terminal in August 2008 and the completion of unplanned maintenance on storage tanks at the Aberdeen terminal during 2008, which had been ongoing since the first quarter of 2008.

Revenues from refined products transportation decreased $6.1 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due a 9% decrease in refined products volumes delivered, partially offset by a 6% increase in the average tariff per barrel. Volume decreases were primarily due to lower distillate volumes resulting from product supply disruptions from downtime at several refineries along the upper Texas Gulf Coast following Hurricanes Gustav and Ike and reduced demand for transportation fuels due to high prices and higher than usual demand from the U.S. Gulf Coast in the 2007 period due to Midwest refinery downtime. The refined products average tariff per barrel increased 6%, primarily due to increases in system tariffs that went into effect on April 1 and July 1, 2008. The volume decreases were partially offset by increases in revenues from the recognition of $2.1 million of deferred revenue in the second quarter of 2008 related to time limit expirations under two transportation agreements without the customers recovering the deferred revenue.

In August and September 2008, the U.S. Gulf Coast was impacted by Hurricanes Gustav and Ike, respectively. These hurricanes resulted in a reduction in availability of product for shipment due to refinery shutdowns affected in preparation for the storms and reduced pipeline capacity due to electric power outages in the wake of the storms. While it is difficult to accurately measure the lost revenues as a result of the hurricanes, we estimate that for the year ended December 31, 2008, revenues of our Downstream Segment were reduced by approximately $3.0 million.

Revenues from LPG transportation increased $4.3 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to a 10% increase in the LPG average tariff per barrel, partially offset by a 5% decrease in the LPG volumes delivered. The LPGs average rate per barrel increased from the prior year, primarily as a result of decreased short-haul deliveries due to the sale of a pipeline on March 1, 2007 to Louis Dreyfus and a July 2008 tariff increase. LPG transportation volumes for the year ended December 31, 2007 included approximately 2.2 million barrels related to short-haul propane movements on the pipeline that was sold. This average rate increase was partially offset by a decrease in long-haul deliveries of propane in the Midwest and Northeast market areas primarily due to the negative demand impact of high prices and scheduled plant maintenance, known as turnarounds.

Other operating revenues increased $4.8 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to a $4.0 million increase in refined products excess inventory revenue, $1.6 million increase in exchanges at the Boligee terminal, a $0.7 million increase in refined products terminaling revenue and a $0.4 million increase in upsystem product exchange revenue, partially offset by a $1.2 million decrease in LPG rental, location exchange and tender deduction revenue and a $1.4 million decrease in product inventory sales. The $1.4 million decrease in product inventory sales was influenced by $7.4 million of losses recognized in the fourth quarter of 2008 offset by a $10.8 million gain recognized during the third quarter of 2008.

Costs and expenses increased $54.1 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. Purchases of petroleum products, discussed above, increased $7.2 million, compared with the prior year. Operating expenses increased $29.7 million primarily due to a $19.8 million increase in pipeline operating and maintenance costs principally related to periodic tank maintenance requirements in 2008 and other repairs and maintenance expenses on various pipeline segments, a $9.3 million lower of cost or market (“LCM”) adjustment on inventory (see Note 7 in the Notes to Consolidated Financial Statements) that resulted from recent significant declines in market prices, a $2.4 million write-off of project costs, a $1.1 million increase in environmental assessment and remediation costs, a $0.9 million increase in expenses related to pipeline tariffs for terminal deliveries, a $1.1 million decrease in product measurement gains and a $0.7 million increase in labor and benefits expense. These increases in operating expenses were partially offset by a $0.7 million decrease in transportation expense related to movements on the Centennial pipeline, a $0.7 million decrease in pipeline rental expense on a third party pipeline and a $0.7 million decrease in pipeline inspection and repair costs associated with our integrity management program. Operating fuel and power increased $0.6 million, primarily due to higher power rates as a result of the increased cost of fuel and true-ups of power accruals. General and administrative expenses decreased $0.4 million primarily due to $1.2 million lower consulting and contract services, partially offset by $0.5 million higher labor and benefits expense. Depreciation expense decreased $3.1 million, primarily due to asset retirements in 2008, partially offset by assets placed into service in 2008. Taxes – other than income taxes increased $1.4 million, primarily due to a higher property asset base in 2008 and true-ups of property tax accruals. During the year ended December 31, 2007, we recognized a net gain of $18.7 million from the sales of various assets in the

Downstream Segment to Enterprise Products Partners and Louis Dreyfus (see Note 10 in the Notes to Consolidated Financial Statements).

Net losses from equity investments increased for the year ended December 31, 2008, compared with the year ended December 31, 2007, as shown below (in thousands):

	For Year Ended December 31, 2008	For Year Ended December 31, 2007	Increase (Decrease)
Centennial	$ (14,673)	$ (13,528)	$ (1,145)
MB Storage	--	1,089	(1,089)
Other	70	43	27
Total equity losses	$ (14,603)	$ (12,396)	$ (2,207)

Equity losses in Centennial increased $1.1 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to lower transportation volumes from the effects of Hurricane Ike, partially offset by lower operating expenses. Volumes on Centennial averaged 112,000 barrels per day during the year ended December 31, 2008, compared with 153,000 barrels per day during the year ended December 31, 2007.

Due to the sale of Mont Belvieu Storage Partners, L.P. (“MB Storage”) on March 1, 2007 to Louis Dreyfus (see Note 10 in the Notes to Consolidated Financial Statements), there were no equity earnings in MB Storage for the year ended December 31, 2008, compared with $1.1 million in earnings for the year ended December 31, 2007. 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 decreased $0.9 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, due to the receipt of various right-of-way payments in 2007.

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

Sales and purchases related to petroleum products marketing activities increased $24.5 million each for the year ended December 31, 2007, compared with the year ended December 31, 2006, primarily due to the acquisition of a refined products terminal in Aberdeen, Mississippi, from Mississippi Terminal and Marketing Inc. on November 1, 2006.

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 decreases, 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 25% increase in the LPG average tariff per barrel, partially offset by a 9% 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 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 LCM 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.

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.

Other income 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.

Upstream Segment

The following table provides financial information for the Upstream Segment for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2008	2007	2006	2008-2007	2007-2006
Operating revenues: (1)					
Sales of petroleum products (2)	$ 12,803,288	$ 9,117,327	$ 9,060,782	$ 3,685,961	$ 56,545
Transportation – Crude oil	57,305	45,952	38,822	11,353	7,130
Other	12,833	10,404	10,025	2,429	379
Total operating revenues	12,873,426	9,173,683	9,109,629	3,699,743	64,054
Costs and expenses: (1)					
Purchases of petroleum products (2)	12,670,933	8,992,048	8,953,407	3,678,885	38,641
Operating expense	61,950	58,976	54,422	2,974	4,554
Operating fuel and power	7,406	7,001	6,989	405	12
General and administrative	9,903	7,619	5,986	2,284	1,633
Depreciation and amortization	20,928	18,257	14,400	2,671	3,857
Taxes – other than income taxes	6,625	5,560	5,390	1,065	170
Gains on sales of assets	(2)	--	(1,805)	(2)	1,805
Total costs and expenses	12,777,743	9,089,461	9,038,789	3,688,282	50,672
Operating income	95,683	84,222	70,840	11,461	13,382
Equity earnings	11,693	2,602	11,905	9,091	(9,303)
Interest income	51	161	407	(110)	(246)
Other income	737	261	388	476	(127)
Earnings before interest	$ 108,164	$ 87,246	$ 83,540	$ 20,918	$ 3,706

(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.

Information presented in the following table includes the margin of the Upstream Segment, which is 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, 2008, 2007 and 2006 is presented below (in thousands, except per barrel and per gallon amounts):

	For Year Ended December 31,			Percentage Increase (Decrease)	
	2008	2007	2006	2008-2007	2007-2006
Margins: (1)					
Crude oil marketing	$ 67,104	$ 72,655	$ 58,358	(8%)	24%
Lubrication oil sales	13,842	8,820	8,565	57%	3%
Revenues: (1)					
Crude oil transportation	89,643	75,285	67,439	19%	12%
Crude oil terminaling (2)	19,071	14,471	11,835	32%	22%
Total margin/revenues	$ 189,660	$ 171,231	$ 146,197	11%	17%
Total barrels/gallons:					
Crude oil marketing(barrels) (1)	254,680	232,041	222,069	10%	4%
Lubrication oil volume (gallons)	21,853	15,344	14,444	42%	6%
Crude oil transportation (barrels)	114,259	96,451	91,487	18%	5%
Crude oil terminaling (barrels)	166,751	135,010	125,974	24%	7%
Margin per barrel or gallon:					
Crude oil marketing (per barrel) (1)	$ 0.263	$ 0.313	$ 0.263	(16%)	19%
Lubrication oil margin (per gallon)	0.633	0.575	0.593	10%	(3%)
Average tariff per barrel:					
Crude oil transportation	$ 0.785	$ 0.781	$ 0.737	1%	6%
Crude oil terminaling	0.114	0.107	0.094	7%	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.

(2) Revenues associated with crude oil terminaling are classified as crude oil transportation in our statements of consolidated income.

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,		
	2008	2007	2006
Sales of petroleum products	$ 12,803,288	$ 9,117,327	$ 9,060,782
Transportation – Crude oil	57,305	45,952	38,822
Less: Purchases of petroleum products	(12,670,933)	(8,992,048)	(8,953,407)
Total margin/revenues	189,660	171,231	146,197
Other operating revenues	12,833	10,404	10,025
Net operating revenues	202,493	181,635	156,222
Operating expense	61,950	58,976	54,422
Operating fuel and power	7,406	7,001	6,989
General and administrative expense	9,903	7,619	5,986
Depreciation and amortization	20,928	18,257	14,400
Taxes – other than income taxes	6,625	5,560	5,390
Gains on sales of assets	(2)	--	(1,805)
Operating income	$ 95,683	$ 84,222	$ 70,840

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Sales of petroleum products and purchases of petroleum products increased $3,686.0 million and $3,678.9 million, respectively, for the year ended December 31, 2008, compared with the year ended December 31, 2007. Operating income increased $11.5 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. The increases in sales and purchases were primarily a result of increased volumes marketed and an increase in the price of crude oil. The average NYMEX price of crude oil was $99.73 per barrel for the year ended December 31, 2008, compared with $72.24 per barrel for the year ended December 31, 2007. Increased volumes transported and marketed and an increase in the price of crude oil, partially offset by increased costs and expenses discussed below, were the primary factors resulting in an increase in operating income.

Crude oil marketing margin decreased $5.6 million, primarily due to increased transportation costs, including increased fuel costs, partially offset by increased volumes marketed and a $0.5 million increase in unrealized gains relating to marking crude oil grade and location swap contracts to current market value. Lubrication oil sales margin increased $5.0 million on higher volumes, primarily due to increased sales of higher margin specialty chemicals and additional margin resulting from the acquisition of Quality Petroleum on August 1, 2008. Crude oil transportation revenues (prior to intercompany eliminations) increased $14.4 million, primarily due to higher transportation volumes on most of our crude oil gathering systems and increases in the tariff rates on certain systems in 2007 and in July 2008. Increased transportation revenues on our Red River, South Texas and Basin systems resulted from movements on higher tariff segments. Additionally, the completion of organic growth projects on our West Texas and South Texas systems increased transportation revenues and volumes on those systems. These increases were partially offset by a $6.0 million increase in the loss on the sale of crude oil inventory reflected in crude oil transportation revenue due to lower crude oil prices in the fourth quarter of 2008. Crude oil terminaling volumes and revenues increased 24% and $4.6 million, respectively, as a result of the completion of three tanks in September 2007, the completion of a tank in August 2008 and as a result of market demand.

Other operating revenues increased $2.4 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. The increase was primarily due to revenues from fuel transportation services of approximately $2.1 million generated as a result of the Quality Petroleum acquisition on August 1, 2008 and an increase in the revenues from documentation and other services to support customers' trading activity at Midland and Cushing.

Costs and expenses increased $3,688.3 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. Purchases of petroleum products, discussed above, increased $3,678.9 million compared with the prior year. Operating expenses increased $3.0 million from the prior year, primarily due to a $6.5 million increase in pipeline operating and maintenance expenses, mostly related to periodic tank maintenance requirements, a $2.5 million increase in operating expenses resulting from the acquisition of Quality Petroleum on August 1, 2008, a $1.6 million increase in pipeline inspection and repair costs associated with our integrity management program, $1.1 million of expense related to initial project development costs for Texas Offshore Port System and a $0.5 million increase in LCM adjustments, partially offset by a $8.0 million decrease in product measurement losses, a $0.6 million decrease in insurance premiums and a $0.6 million decrease in labor and benefits expense. Operating fuel and power increased $0.4 million primarily as a result of higher fuel costs and higher transportation volumes. General and administrative expenses increased $2.3 million, primarily due to a $1.0 million write-off of receivables as a result of a customer bankruptcy, a $0.5 million write-off of project costs and a $0.5 million increase in labor and benefits expense. Depreciation and amortization expense increased $2.7 million primarily due to assets placed into service in 2007. Taxes – other than income taxes increased $1.1 million due to true-ups of property tax accruals.

Equity earnings from our investment in Seaway increased $9.1 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. Equity earnings from our investment in Seaway increased, primarily due to increased transportation revenues from volumes transported on a spot basis, which are transported at higher tariff rates, and an increase in long-haul transportation volumes compared to the prior year as a result of the unexpected temporary shutdown of several regional refineries for maintenance and repairs in the 2007 period and a decrease in product measurement losses. These increases in equity earnings from our investment in Seaway were partially offset by an increase in pipeline operating and maintenance expenses, a decrease in transportation volumes resulting from the effects of Hurricane Ike, a $1.4 million loss in equity earnings resulting from the loss on the sale of crude oil inventory due to lower crude oil prices in the fourth quarter of 2008 and a $0.2 million decrease in equity earnings resulting from repairs and maintenance expenses related to Hurricane Ike. Long-haul volumes on Seaway averaged 208,000 barrels per day during the year ended December 31, 2008, compared with 135,000 barrels per day during the year ended December 31, 2007.

Other income increased $0.5 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to the receipt of $0.6 million of royalty income.

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 new accounting guidance 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 oil pipeline assets to Enterprise Products Partners.

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.

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.

Midstream Segment

The following table provides financial information for the Midstream Segment for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	For Year Ended December 31,			Increase (Decrease)	
	2008	2007	2006	2008-2007	2007-2006
Operating revenues: (1)					
Sales of petroleum products (2)	$ --	$ --	$ 18,766	$ --	$ (18,766)
Gathering – Natural gas	57,097	61,634	123,933	(4,537)	(62,299)
Transportation – NGLs (3)	52,192	46,542	43,838	5,650	2,704
Other	13,128	14,059	14,732	(931)	(673)
Total operating revenues	122,417	122,235	201,269	182	(79,034)
Costs and expenses: (1)					
Purchases of petroleum products	--	--	17,272	--	(17,272)
Operating expense	26,367	29,395	42,887	(3,028)	(13,492)
Operating fuel and power	16,410	14,551	12,107	1,859	2,444
General and administrative expense	9,717	9,109	8,277	608	832
Depreciation and amortization	39,323	40,827	52,447	(1,504)	(11,620)
Taxes – other than income taxes	3,041	2,586	4,156	455	(1,570)
Gains on sales of assets	--	--	(1,376)	--	1,376
Total costs and expenses	94,858	96,468	135,770	(1,610)	(39,302)
Operating income	27,559	25,767	65,499	1,792	(39,732)
Equity earnings (1)	90,004	83,060	35,052	6,944	48,008
Interest income	384	636	662	(252)	(26)
Other income	--	--	6	--	(6)
Earnings before interest	$ 117,947	$ 109,463	$ 101,219	$ 8,484	$ 8,244

(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 $13.8 million, $13.2 million and $10.2 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents volume and average rate information for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,			Percentage Increase (Decrease)	
	2008	**2007**	**2006**	**2008-2007**	**2007-2006**
Gathering – Natural Gas – Jonah: (1) (2)					
MMcf	709,915	587,354	473,909	21%	24%
BBtu	784,179	647,890	522,667	21%	24%
Average fee per Mcf	$ 0.257	$ 0.236	$ 0.224	9%	5%
Average fee per MMBtu	$ 0.233	$ 0.214	$ 0.204	9%	5%
Gathering – Natural Gas – Val Verde: (2)					
MMcf	166,914	175,667	181,928	(5%)	(3%)
BBtu	149,095	155,982	160,929	(5%)	(3%)
Average fee per Mcf	$ 0.342	$ 0.351	$ 0.359	(3%)	(2%)
Average fee per MMBtu	$ 0.383	$ 0.395	$ 0.406	(3%)	(3%)
Transportation and movements – NGLs:					
Transportation barrels (in thousands)	62,647	64,199	63,396	(2%)	1%
Lease barrels (in thousands) (3)	10,982	12,797	6,350	(14%)	102%
Average rate per barrel	$ 0.783	$ 0.688	$ 0.674	14%	2%
Natural Gas Sales: (1)					
BBtu	4,908	14,774	10,206	(67%)	45%
Average fee per MMBtu	$ 6.374	$ 4.278	$ 4.984	49%	(14%)
Fractionation – NGLs:					
Barrels (in thousands)	4,232	4,175	4,406	1%	(5%)
Average rate per barrel	$ 1.753	$ 1.768	$ 1.662	(1%)	6%
Sales – Condensate: (1) (4)					
Barrels (in thousands)	76.9	89.7	74.2	(14%)	21%
Average rate per barrel	$ 74.02	$ 59.57	$ 62.26	24%	(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 (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, 2008, 2007 and 2006.
(2) The majority of volumes in Val Verde's contracts are measured in Mcf, 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, 2008 and 2007, our ownership interest in Jonah was approximately 80.64%, and at December 31, 2006, our ownership interest was approximately 85.55% (see Note 9 in the Notes to Consolidated Financial Statements).

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Natural gas gathering revenues from the Val Verde system decreased $4.5 million, and volumes gathered decreased 8.8 Bcf for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to lower production as a result of more severe winter weather during the first quarter of 2008 and 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, 2008, Val Verde's gathering volumes averaged 457 MMcf per day, compared with 481 MMcf per day for the year ended December 31, 2007. Val Verde's average natural gas gathering fees decreased 3%, 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.

Revenues from the transportation of NGLs increased $5.7 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to an increase in the average rate on the Chaparral Pipeline as a result of transporting a higher percentage of long-haul volumes on the system and an increase in the average rate on the Panola Pipeline, partially offset by slightly lower transportation volumes due to the unexpected reduction of deliveries on the Chaparral and Panola Pipelines resulting from the effects of Hurricane Ike.

Other operating revenues decreased $0.9 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to decreases on the Chaparral and Panola Pipelines as a result of decreased revenues and volumes from pipeline capacity leases. Volumes transported under pipeline capacity leases decreased 14% during the year ended December 31, 2008, compared with the year ended December 31, 2007, due to customers shipping less NGLs under the capacity lease agreements and due to the effects of Hurricane Ike.

Costs and expenses decreased $1.6 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. Operating expenses decreased $3.0 million from the prior year, primarily due to a $4.7 million decrease as a result of lower product measurement losses, a $1.8 million decrease in insurance premiums, a $1.6 million decrease in pipeline inspection and repair costs associated with our integrity management program and a $0.6 million decrease in labor and benefits expense, partially offset by a $4.0 million increase in pipeline operating and maintenance expenses and a $1.7 million increase in LCM adjustments. Operating fuel and power increased $1.9 million primarily due to higher power costs on the Chaparral Pipeline. General and administrative expenses increased $0.6 million primarily due to higher professional services expense and higher labor and benefits expense. Depreciation and amortization expense decreased $1.5 million, primarily due to a decrease in amortization expense on Val Verde as a result of a decrease in volumes on contracts which are included in intangible assets and amortized under the units-of-production method. Taxes – other than income taxes increased $0.5 million primarily due to true-ups of property tax accruals.

Equity earnings from our investment in Jonah increased $6.9 million for the year ended December 31, 2008, compared with the year ended December 31, 2007. Earnings increased primarily due to a $45.5 million increase in natural gas gathering revenues and an increase in volumes from the completion of the Phase V expansion, partially offset by a $15.0 million increase in depreciation and amortization expense primarily relating to portions of the Phase V expansion being placed in service as they were completed, $2.5 million of expense related to the abandonment of approximately 42 miles of pipeline and a $3.9 million increase in operating, general and administrative expenses. For the year ended December 31, 2008 and 2007, Jonah's gathering volumes averaged approximately 1.9 Bcf per day and 1.6 Bcf per day, respectively, and total volumes gathered increased 122.6 Bcf. For the year ended December 31, 2008, our sharing in the earnings of Jonah was 80.64%, compared with 89.79% in the prior year, as a result of certain milestones provided for in the joint venture agreement being reached in the construction of the Phase V expansion (see Note 9 in the Notes to Consolidated Financial Statements). Through December 31, 2008, we have reimbursed Enterprise Products Partners $306.5 million ($44.9 million in 2008, $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).

The decrease in Jonah's natural gas sales volumes for the year ended December 31, 2008, compared with the prior year, was primarily a result of certain shippers selling gas themselves, rather than through Jonah. The increase in Jonah's natural gas sales average fee per MMBtu was primarily a result of higher market prices in the 2008 period. As a result of lower gathering system pressures, more condensate was being removed at the wellhead and sold by producers, instead of being gathered by Jonah, resulting in a decrease in Jonah's condensate sales volumes from the prior year. The increase in Jonah's average condensate rate per barrel was primarily a result of higher market prices in 2008 compared with the year ended December 31, 2007.

Interest income decreased $0.3 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, due to lower interest income earned on cash investments and other investing activities.

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 net income 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 a $7.2 million increase in operating, general and administrative expenses and a $11.1 million increase in 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.

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.

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 (in thousands):

	For Year Ended December 31, 2006
Operating revenues:	
Sales of petroleum products	$ 3,828
Other	932
Total operating revenues	4,760
Costs and expenses:	
Purchases of petroleum products	3,000
Operating expense	182
Depreciation and amortization	51
Taxes – other than income taxes	30
Total costs and expenses	3,263
Income from discontinued operations	$ 1,497

Sales of petroleum products less purchases of petroleum products resulting from the processing activities at the Pioneer plant were $3.8 million for the year ended December 31, 2006. 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 2006, the producers elected the fee plus keep-whole arrangement.

Marine Services Segment

The following table provides financial information for the Marine Services Segment for the year ended December 31, 2008 (in thousands):

	For Year Ended December 31, 2008	2007	Increase (Decrease)
Operating revenues:			
Transportation – Marine	$ 164,265	$ --	$ 164,265
Other	9	--	9
Total operating revenues	164,274	--	164,274
Costs and expenses:			
Operating expense	64,353	--	64,353
Operating fuel and power	34,727	--	34,727
General and administrative	5,243	--	5,243
Depreciation and amortization	23,015	--	23,015
Taxes – other than income taxes	2,423	--	2,423
Loss on the sale of assets	6	--	6
Total costs and expenses	129,767	--	129,767
Operating income	34,507	--	34,507
Interest income	13	--	13
Earnings before interest	$ 34,520	$ --	$ 34,520

Information presented in the following table includes gross margin and the average daily rate for our Marine Services Segment, which are non-GAAP financial measures under the rules of the SEC. We calculate gross margin as marine transportation revenues less operating expense and operating fuel and power, and average daily rate is calculated as gross margin divided by fleet operating days. We believe gross margin, in conjunction with average daily rate, are meaningful measures of the financial performance of our Marine Services Segment, in which we provide services under different types of contracts with varying arrangements for the payment of fuel costs and other operational fees. These measures allow for comparability of results across our different contracts within a given period, as well as between periods. Further, our management uses these measures internally to assist them in evaluating segment results and making decisions regarding the use and deployment of our marine vessels.

Marine Services Segment operating statistics as of December 31, 2008, are set forth in the following table (dollars in thousands, except average daily rate):

Number of inland tow boats	45
Number of inland tank barges	105
Number of offshore tow boats	6
Number of offshore tank barges	8
Fleet available days (1)	51,932
Fleet operating days (2)	48,308
Fleet utilization (3)	93%
Gross margin	$65,194
Average daily rate (4)	$1,350

(1) Equal to the number of calendar days from our acquisition of Cenac on February 1, 2008 and Horizon on February 29, 2008 through December 31, 2008 multiplied by the total number of vessels less the aggregate number of days that our vessels are not operating due to scheduled maintenance and repairs or unscheduled instances where vessels may have to be drydocked in the event of accidents and other unforeseen damage.
(2) Equal to the number of our fleet available days from our acquisition of Cenac on February 1, 2008 and Horizon on February 29, 2008 through December 31, 2008 less the aggregate number of days that our vessels are off-hire.
(3) Equal to the number of fleet operating days divided by the number of fleet available days during the period.
(4) Equal to gross margin divided by the number of fleet operating days during the period.

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

	For Year Ended December 31, 2008
Transportation – Marine	$ 164,265
Other operating revenues	9
Operating expense	64,353
Operating fuel and power	34,727
Gross margin	65,194
General and administrative	5,243
Depreciation and amortization	23,015
Taxes – other than income taxes	2,423
Loss on sale of assets	6
Operating income	$ 34,507

Revenues from marine transportation were $164.3 million for the year ended December 31, 2008, of which $115.1 million related to inland transportation services and $49.2 million related to offshore transportation and well-testing services. Inland and offshore transportation service revenue included $38.0 million and $2.3 million, respectively, of reimbursements for the cost of fuel and other specified operational fees reimbursed by customers.

Revenues were primarily influenced by rates on term contracts along with industry demand, high utilization rates of tank barges and reimbursements of costs of fuel and other specified operational fees that are recovered under most of the transportation contracts. Gross margin was $65.2 million for the year ended December 31, 2008 and the average daily rate was $1.35 thousand. The level of gross margin we achieve and the average daily rate are primarily influenced by rates on term and spot contracts and renewal of term contracts along with industry demand. Operating expenses, such as vessel personnel salaries and related employee benefits and tow boat and tank barge maintenance expenses, also impact the level of gross margin and the average daily rate.

From the date of our acquisitions of Cenac and Horizon (see Note 10 in the Notes to Consolidated Financial Statements) through the end of the third quarter 2008, as the customer contracts become subject to annual renewal, we obtained renewals of substantially all contracts at increased day rates. During the fourth quarter 2008, there were five inland customer affreightment contracts that were not renewed due to general economic conditions. The marine vessels impacted by these non-renewals will be employed in the spot market until we can secure term contracts. As a result, our fleet utilization may be reduced during 2009 compared to 2008 levels.

Costs and expenses were $129.8 million for the year ended December 31, 2008. Operating expenses were $64.4 million, consisting primarily of $35.9 million of payments under the transitional operating agreement for vessel personnel salaries, related employee benefits and other expenses, $8.5 million in operating supplies and expenses, $8.4 million of tow boat and tank barge maintenance expenses, $8.3 million for third-party services and $2.6 million in insurance premiums. Operating fuel and power was $34.7 million relating to diesel fuel consumed under the term contracts, under which substantially all fuel costs are directly reimbursed by the customer to recover the cost of fuel. General and administrative expenses were $5.2 million, consisting primarily of $2.6 million related to the monthly service fee and overhead fees that we paid to Cenac under the transitional operating agreement, a $1.3 million write-off of receivables in the third quarter of 2008 as a result of a customer bankruptcy and $0.8 million of labor and benefits expenses. Depreciation and amortization expense was $23.0 million, consisting of $15.4 million of depreciation expense on tow boats and tank barges and $7.6 million of amortization expense related to customer relationship intangible assets, non-compete agreements and other intangible assets acquired in the Cenac and Horizon acquisitions. Taxes – other than income taxes was $2.4 million and related primarily to payroll taxes.

Interest Expense and Capitalized Interest

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Interest expense increased $46.9 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to higher outstanding borrowings in 2008 and $8.7 million in interest expense recognized upon the redemption of the 7.51% TE Products Senior Notes on January 28, 2008. Of the $8.7 million of expense, $6.6 million related to a make-whole premium paid with the redemption of the senior notes (see Note 12 in the Notes to Consolidated Financial Statements), $1.0 million related to the remaining unamortized interest rate swap loss that had been deferred as an adjustment to the carrying value of the senior notes (see Note 6 in the Notes to Consolidated Financial Statements) and $1.1 million related to unamortized debt issuance costs on the senior notes. Additionally, the increase in interest expense was due to $3.6 million of interest expense in 2008 resulting from interest payments hedged under treasury locks not occurring as forecasted (see Note 6 in the Notes to Consolidated Financial Statements). These increases were partially offset by lower short-term floating interest rates in 2008.

Capitalized interest (included in interest expense, net in our statements of consolidated income) increased $8.1 million for the year ended December 31, 2008, compared with the year ended December 31, 2007, primarily due to higher construction work-in-progress balances in 2008 as compared to 2007.

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 2006.

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, 2008 and 2007, we had current tax liabilities of $3.9 million and $1.2 million, respectively. At December 31, 2008, we had a deferred tax liability of less than $0.1 million while at December 31, 2007, we had a deferred tax asset of less than $0.1 million. During the years ended December 31, 2008 and 2007, we recorded increases in current income tax liabilities of $4.5 million and $1.2 million, respectively. During the years ended December 31, 2008 and 2007, we recorded a less than $0.1 million increase to deferred tax liability and a $0.7 million reduction to deferred tax liability, respectively. The offsetting net charges to deferred tax expense and income tax expense are shown on our statements of consolidated income as provision for income taxes.

Financial Condition and Liquidity

Cash generated from operations, distributions from our joint ventures, borrowings under our credit facilities and debt and equity offerings are our primary sources of liquidity. From time to time we may dispose of assets, which would provide an additional source of liquidity. At December 31, 2008, we had a working capital surplus of $7.6 million, while at December 31, 2007, we had a working capital deficit of $431.2 million. 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, 2008, we had approximately $404.4 million in available borrowing capacity under our revolving credit facility. Cash flows for the years ended December 31, 2008, 2007 and 2006 were as follows (in thousands):

	For Year Ended December 31,		
	2008	2007	2006
Cash provided by (used in):			
Continuing operating activities	$ 346,861	$ 350,572	$ 271,552
Operating activities	346,861	350,572	273,073
Investing activities	(831,020)	(317,400)	(273,716)
Financing activities	484,164	(33,219)	594

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Operating Activities

Net cash flow provided by operating activities was $346.9 million for the year ended December 31, 2008 compared to $350.6 million for the year ended December 31, 2007. The following were the principal factors resulting in the $3.7 million decrease in net cash flows provided by operating activities:

§ Cash flow from operating activities decreased due to the timing of cash receipts and cash disbursements related to working capital components.

§ Cash distributions received from unconsolidated affiliates increased $23.2 million. Distributions from our equity investment in Jonah increased $32.1 million primarily due to increased revenues and volumes generated from completion of the Phase V expansion. Distributions received from our equity investment in Seaway increased $1.4 million primarily due to increased earnings in 2008 as compared to 2007. In 2007, we received distributions from our equity investment in MB Storage of $10.4 million. We sold our interest in MB Storage on March 1, 2007 (see Note 10 in the Notes to Consolidated Financial Statements).

§ Cash paid for interest, net of amounts capitalized, increased $23.9 million year-to-year primarily due to the increase in debt outstanding, including higher outstanding balances on our variable rate revolving credit facility. Excluding the effects of hedging activities and interest capitalized during the year ended December 31, 2009, we expect interest payments on our fixed rate senior notes and junior subordinated notes for 2009 to be approximately $139.6 million. We expect to make our interest payments with cash flows from operating activities.

Investing Activities

Net cash flow used in investing activities was $831.0 million for the year ended December 31, 2008 compared to $317.4 million for the year ended December 31, 2007. The following were the principal factors resulting in the $513.6 million increase in net cash flows used in investing activities:

§ Cash used for business combinations was $351.3 million during the year ended December 31, 2008, of which $258.2 million was for the Cenac acquisition, $87.5 million was for the Horizon acquisition and $5.6 million was for the Quality Petroleum acquisition (see Note 10 in the Notes to Consolidated Financial Statements).

§ Capital expenditures increased $72.2 million primarily due to an increase in organic growth projects year-to-year and higher spending to sustain existing operations, including pipeline integrity. Cash paid for linefill on assets owned decreased $26.6 million year-to-year primarily due to the timing of completion of organic growth projects in our Upstream Segment.

§ Proceeds from the sales of assets and ownership interests during 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.

§ Investments in unconsolidated affiliates decreased $32.9 million, which includes an $11.1 million decrease in contributions to Centennial and a $57.8 million decrease in contributions to Jonah primarily related to completion of its Phase V expansion in 2008. 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. These decreases were partially offset by $36.0 million in contributions to Texas Offshore Port System for the year ended December 31, 2008 (see Note 9 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.

§ During the years ended December 31, 2008 and 2007, we paid $0.7 million and $3.3 million, respectively, related to the acquisition of intangible assets.

Financing Activities

Cash flows provided by financing activities totaled $484.2 million for the year ended December 31, 2008, compared to cash flows used in financing activities of $33.2 million for the year ended December 31, 2007. The following were the principal factors resulting in the $517.4 million increase in cash provided by financing activities:

§ During the year ended December 31, 2008, we used $1.0 billion of proceeds from our term credit agreement (i) to fund the cash portion of our Cenac and Horizon acquisitions, (ii) to fund the redemption of our 7.51% TE Products Senior Notes in January 2008 and the repayment of our 6.45% TE Products Senior Notes, which matured in January 2008, (iii) to repay $63.2 million of debt assumed in the Cenac acquisition, and (iv) for other general partnership purposes. We used the proceeds from the issuance of senior notes in March 2008 to repay the outstanding balance of $1.0

billion under the term credit agreement (see Note 12 in the Notes to Consolidated Financial Statements). Debt issuance costs paid during the year ended December 31, 2008 were $9.9 million.

§ We received $295.8 million from the issuance in May 2007 of our 7.000% junior subordinated notes due September 2067 (net of debt issuance costs of $3.7 million) (see Note 12 in the Notes to Consolidated Financial Statements).

§ Net borrowings under our revolving credit facility increased $26.7 million.

§ We paid $52.1 million to settle treasury locks in March 2008 (see Note 6 in the Notes to Consolidated Financial Statements) upon the issuance of senior notes. 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.

§ Cash distributions to our partners increased $33.5 million year-to-year due to an increase in the number of Units outstanding and an increase in our quarterly cash distribution rate per Unit. We paid cash distributions of $328.0 million ($2.84 per Unit) and $294.5 million ($2.74 per Unit) during the years ended December 31, 2008 and 2007, respectively. Additionally, we declared a cash distribution of $0.725 per Unit for the quarter ended December 31, 2008. We paid the distribution of $91.2 million on February 6, 2009 to unitholders of record on January 30, 2009.

§ We received $257.0 million in net proceeds from an underwritten equity offering in September 2008 from the public issuance of 9.2 million Units (see Note 13 in the Notes to Consolidated Financial Statements) and $7.0 million from the sale of 241,380 unregistered Units to TEPPCO Unit (see Note 4 in the Notes to Consolidated Financial Statements).

§ Net proceeds from the issuance of Units to employees under the employee unit purchase plan and the issuance of Units in connection with our distribution reinvestment plan ("DRIP") were $12.2 million for the year ended December 31, 2008, compared to $1.7 million for the year ended December 31, 2007 (see Note 13 in the Notes to Consolidated Financial Statements).

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 was 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 was been contracted for sale in 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.

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. 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; 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 were $51.6 million, of which $38.0 million related to cash proceeds received from the sale of the Pioneer plant in the Midstream Segment 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.

§ 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. For the year ended December 31, 2006, cash paid for the acquisition of assets was $4.8 million for Downstream Segment assets.

§ Cash used for business combinations for the year ended December 31, 2006 was $15.7 million for Downstream Segment assets.

§ During the year ended December 31, 2007, we paid $3.3 million related to the acquisition of intangible assets.

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.

§ 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.

§ 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).

§ 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.

§ 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.

Other Considerations

Equity Offering and Registration Statement

In September 2008, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities and removed from registration securities remaining under our previous universal shelf registration statement.

On September 9, 2008, we issued and sold in an underwritten public offering 9.2 million Units at a price to the public of $29.00 per Unit, including 1.2 million Units sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. The proceeds from the offering, net of underwriting discount and offering expenses, totaled approximately $257.0 million. Concurrently with this offering, we sold 241,380 unregistered Units at the public offering price of $29.00 to TEPPCO Unit. The net proceeds from the offering and the unregistered issuance to TEPPCO Unit were used to reduce indebtedness under our revolving credit facility.

We also have on file with the SEC a registration statement registering the issuance of up to 10,000,000 Units in connection with our DRIP. The DRIP provides unitholders of record and beneficial 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 of our Partnership. As of December 31, 2008, 418,233 Units have been issued since the implementation of the DRIP, generating $13.0 million in net proceeds that we used for general partnership purposes. In November 2008, affiliates of EPCO reinvested $3.3 million in Units issued under the DRIP.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,000,000 Units. Under this plan, employees of EPCO can purchase our Units at a 10.0% discount through payroll deductions. During the year ended December 31, 2008, we issued 23,097 Units to employees under this plan, which generated proceeds of $0.8 million.

Credit Facilities

We have in place an unsecured revolving credit facility, including the issuance of letters of credit ("Revolving Credit Facility"), which matures on December 12, 2012. The Revolving Credit Facility allows us to request unlimited one-year extensions of the maturity date, subject to lender approval and satisfaction of certain other conditions. In July 2008, commitments under our facility were increased from $700.0 million to $950.0 million. The aggregate outstanding principal amount of swing line loans or same day borrowings permitted under the Revolving Credit Facility is $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.

During September 2008, Lehman Brothers Bank, FSB ("Lehman"), which had a 4.05% participation in our Revolving Credit Facility, stopped funding its commitment following the bankruptcy filing of its parent. Assuming that future fundings are not received for the Lehman percentage commitment, aggregate available capacity would be reduced by approximately $28.9 million.

At December 31, 2008, $516.7 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 1.4%, leaving approximately $404.4 million in available borrowing capacity, after considering the reduction in the available capacity related to Lehman discussed above. The Revolving Credit Facility contains financial covenants that require us to maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 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 12 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). At December 31, 2008, we were in compliance with the covenants of the Revolving Credit Facility.

In December 2007, we put in place a senior unsecured term credit agreement ("Term Credit Agreement"), with a borrowing capacity of $1.0 billion and a maturity date of December 19, 2008. During the first quarter of 2008, we borrowed $1.0 billion (i) to fund the cash portion of our Cenac and Horizon acquisitions, (ii) to fund the redemption of our 7.51% TE Products Senior Notes in January 2008 and the repayment of our 6.45% TE Products Senior Notes, which matured in January 2008, (iii) to repay $63.2 million of debt assumed in the Cenac acquisition, and (iv) for other general partnership purposes. In March 2008, we repaid the outstanding balance with proceeds from the issuance of senior notes and other cash on hand and terminated the credit agreement.

Senior Notes

On March 27, 2008, we issued and sold in an underwritten public offering (i) $250.0 million principal amount of 5.90% Senior Notes due 2013, (ii) $350.0 million principal amount of 6.65% Senior Notes due 2018, and (iii) $400.0 million principal amount of 7.55% Senior Notes due 2038. The proceeds of this offering were used to repay borrowings outstanding under our Term Credit Agreement, which was terminated in March 2008 (see Note 12 in the Notes to Consolidated Financial Statements). The Senior Notes were issued at discounts of $0.2 million, $1.3 million and $2.2 million, respectively, and are being accreted to their face value over the applicable terms 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 50 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, 2008, we were in compliance with the covenants of these senior notes.

Junior Notes and Other Long-Term Debt

For information regarding our junior subordinated notes and other long-term debt obligations, please refer to “Junior Subordinated Notes” and the second and fourth paragraphs under “Senior Notes” in Note 12 in our Notes to Consolidated Financial Statements which are incorporated by reference herein.

Retirement of TE Products Senior Notes

In January 2008, TE Products retired all of its outstanding debt by repaying at maturity $180.0 million principal amount of its 6.45% TE Products Senior Notes due 2008 and redeeming the remaining $175.0 million principal amount of its 7.51% TE Products Senior Notes due 2028. The redemption price for the 7.51% TE Products Senior Notes due 2028 was 103.755% of the principal amount plus accrued and unpaid interest to January 28, 2008, the date of redemption. We funded the retirement of the TE Products debt 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 2009 will be approximately $340.0 million (including approximately $17.0 million of capitalized interest). Excluding capitalized interest, we expect to spend approximately $270.0 million for revenue generating projects, which includes $170.0 million for our expected spending on the Motiva project. We expect to spend approximately $49.0 million to sustain existing operations (including $16.0 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 $4.0 million to improve operational efficiencies and reduce costs among all of our business segments.

Additionally, we expect to invest approximately $27.0 million in our Jonah joint venture during 2009 for the completion of additional facilities to expand the Pinedale field production.   We expect to invest approximately $70.0 million in 2009 as our net contribution to our Texas Offshore Port System joint venture.

During 2009, 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, joint venture distributions, debt or the issuance of additional equity, and the possible disposition of assets.

Liquidity Outlook

Our primary cash requirements consist of (i) ordinary course operating uses, such as operating expenses, capital expenditures to sustain existing operations, interest payments on our outstanding debt and distributions to our unitholders and General Partner, (ii) growth expenditures, such as capital expenditures for revenue generating activities (including Jonah and Texas Offshore Port System) and acquisitions of new assets or businesses and (iii) repayment of principal on our long-term debt. Our ordinary course operating cash requirements for 2009 are expected to be funded through our cash flows from operating activities. We have no material long-term debt obligations that mature in 2009, and our Revolving Credit Facility does not mature until 2012. We expect cash requirements for growth expenditures and long-term debt repayments will be funded by a combination of several sources, including cash flows from operating activities, borrowings under credit facilities, joint venture distributions, the issuance of additional equity and debt securities and the possible disposition of assets. See Note 12 in the Notes to Consolidated Financial Statements.

Our ability to maintain adequate liquidity depends on our ability to have continued access to the financial markets and continue to generate cash from operations, both of which are subject to a number of factors, including prevailing market conditions, the possibility of a prolonged economic slowdown and general competitive, legislative, regulatory and other market factors that are beyond our control. See Item 1A, Part I. Risk Factors.

It is our belief that we will continue to have adequate liquidity to fund future recurring operating and investing activities. For a discussion of our liquidity outlook, see "General Outlook for 2009" within this Item 7.

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 and the limited guarantee of Centennial catastrophic events as discussed below. In addition, we have entered into various operating leases covering assets utilized in several areas of our operations.

At December 31, 2008 and 2007, Centennial's debt obligations consisted of $129.9 million and $140.0 million, respectively, borrowed under a master shelf loan agreement. In January 2008, we entered into an amended and restated guaranty agreement ("Amended Guaranty") with Centennial's lenders, under which we, TE Products, TEPPCO Midstream and TCTM (collectively, the "TEPPCO Guarantors") are required, on a joint and several basis, to pay 50% of any past-due amount under Centennial's master shelf loan agreement not paid by Centennial. The Amended Guaranty also has a credit maintenance requirement whereby we may be required to provide additional credit support in the form of a letter of credit or pay certain fees if either of our credit ratings from Standard & Poor's Ratings Group ("S&P") and Moody's Investors Service, Inc. ("Moody's") falls below investment grade levels as specified in the Amended Guaranty. If Centennial defaults on its debt obligations, the estimated maximum potential amount of future payments for the TEPPCO Guarantors and Marathon Petroleum Company LLC ("Marathon") is $65.0 million each at December 31, 2008. At December 31, 2008, we have a liability of $9.0 million, which is based upon the expected present value of amounts 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, 2008, TE Products has a liability of $3.9 million, which is based upon the expected present value of amounts 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 pieces of equipment. We currently estimate that our minimum lease payment related to this equipment will be $3.9 million for 2009. 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, 2008 (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	$ 516,654	$ --	$ --	$ 516,654	$ --
7.625% Senior Notes due 2012 (1)	500,000	--	--	500,000	--
6.125% Senior Notes due 2013 (1)	200,000	--	--	200,000	--
5.90% Senior Notes due 2013 (1)	250,000	--	--	250,000	--
6.65% Senior Notes due 2018 (1)	350,000	--	--	--	350,000
7.55% Senior Notes due 2038 (1)	400,000	--	--	--	400,000
7.00% Junior Subordinated Notes due 2067 (1)	300,000	--	--	--	300,000
Interest payments (2)	2,624,102	146,838	293,677	215,449	1,968,138
Debt and interest subtotal	$ 5,140,756	$ 146,838	$ 293,677	$ 1,682,103	$ 3,018,138
Operating leases (3)	$ 55,696	$ 12,467	$ 20,352	$ 15,201	$ 7,676
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligation:					
Crude oil	$ 212,435	$ 212,435	$ --	$ --	$ --
Refined Products	$ 10,594	$ 10,594	$ --	$ --	$ --
Other	$ 3,057	$ 1,772	$ 884	$ 401	$ --
Underlying major volume commitments:					
Crude oil (in MBbls)	4,409	4,409	--	--	--
Refined Products (in MBbls)	353	353	--	--	--
Service payment commitments (5)	$ 5,024	$ 4,675	$ 349	$ --	$ --
Contributions to Jonah (6)	$ 27,000	$ 27,000	$ --	$ --	$ --
Contributions to Texas Offshore Port System (7)	$ 70,000	$ 70,000	$ --	$ --	$ --
Capital expenditure obligations (8)	$ 116,733	$ 116,733	$ --	$ --	$ --
Other liabilities and deferred credits (9)	$ 28,826	$ --	$ 11,223	$ 7,703	$ 9,900
Total	$ 5,674,883	$ 607,276	$ 326,485	$ 1,705,408	$ 3,035,714

(1) At December 31, 2008, the 7.625% Senior Notes includes a deferred gain of $18.1 million, net of amortization, from interest rate swap terminations (see Note 6 in the Notes to Consolidated Financial Statements). At December 31, 2008, our senior notes and our junior subordinated notes include an aggregate of $5.2 million of unamortized debt discounts. The deferred gain and the unamortized debt discounts are excluded from this table.

(2) 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 amounts calculated on the Revolving Credit Facility and the junior subordinated notes are based on the assumption that the amounts outstanding and the interest rates charged both remain at their current levels.

(3) 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, 2008, 2007 and 2006, was $20.0 million, $22.1 million and $25.3 million, respectively.

(4) 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, 2008. 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.

(5) Includes approximately $4.5 million related to a shipment commitment on Centennial, approximately $0.4 million related to a commitment to pay for compression services on Val Verde and approximately $0.1 million related to the monthly service fee we pay Cenac to operate the marine assets in accordance with the transitional operating agreement.
(6) Expected contributions to Jonah in 2009 for our share of capital expenditures.
(7) Expected contributions to Texas Offshore Port System for our share of costs related to the TOPS and PACE projects. We are obligated under the joint venture agreement to contribute one-third of the funds to complete the projects, which we currently estimate will total $600.0 million for our share.
(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) Includes approximately $9.6 million of long-term deferred revenue payments, primarily in the Downstream and Upstream segments, which are being recognized into income as the services are performed and approximately $12.0 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.

Summary of Related Party Transactions

The following table summarizes our revenue and expense transactions with related parties for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	For Year Ended December 31,		
	2008	**2007**	**2006**
Revenues from EPCO and affiliates:			
Sales of petroleum products	$ 715	$ 320	$ 3,165
Transportation – NGLs	13,785	13,153	10,225
Transportation – LPGs	8,735	5,191	3,648
Other operating revenues	13,318	1,761	1,517
Revenues from unconsolidated affiliates:			
Other operating revenues	91	351	295
Related party revenues	$ 36,644	$ 20,776	$ 18,850
Costs and Expenses from EPCO and affiliates:			
Purchases of petroleum products	$ 132,624	$ 61,596	$ 52,982
Operating expense	104,878	96,947	103,924
General and administrative	31,601	25,500	21,709
Costs and Expenses from unconsolidated affiliates:			
Purchases of petroleum products	7,143	5,493	2,987
Operating expense	7,926	8,736	5,094
Costs and Expenses from Cenac and affiliates:			
Operating expense	45,382	--	--
General and administrative	2,912	--	--
Related party expenses	$ 332,466	$ 198,272	$ 186,696

For additional information regarding our related party transactions, see Note 15 in the Notes to Consolidated Financial Statements.

Credit Ratings

As of March 2, 2009, our debt securities are rated BBB- by S&P, Baa3 by Moody's and BBB- by Fitch Ratings, all with stable outlooks. Such ratings reflect only the view of the rating agency and should not be interpreted as a recommendation to buy, sell or hold our securities. These ratings may be revised or withdrawn at any time by the agencies at their discretion and should be evaluated independently of any other rating. 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. Fitch Ratings assigned 75% equity treatment to these notes.

Recent Accounting Pronouncements

On January 1, 2008, we adopted the provisions of SFAS No. 157, *Fair Value Measurements*, that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 6 in the Notes to Consolidated Financial Statements for information regarding fair value disclosures pertaining to our financial assets and liabilities.

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 our 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 related 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 financial instruments such as swaps and other hedging instruments. Generally, we elect hedge accounting where permitted under SFAS 133. The terms of these contracts are typically one year or less. The purpose of such hedging activity is to either balance our inventory position or lock in a profit margin. For financial instruments where cash flow 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 financial instruments 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, 2008, we had no commodity financial instruments that were accounted for as cash flow hedges. Gains and losses for financial instruments used in cash flow hedges are offset against corresponding gains or losses of the hedged item and are deferred in other comprehensive income. No ineffectiveness was recognized as of December 31, 2008. In addition, we had some commodity financial instruments 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, 2008 was an asset of $3 thousand.

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, 2007	December 31, 2008	February 3, 2009
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (18,897)	$ 3	$ (200)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(33,606)	9	(199)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(4,188)	(4)	(198)

The fair value of the open positions was based upon both quoted market prices obtained from NYMEX and 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, the volumes for the applicable month and applicable discount rate.

Interest Rate Risk Hedging Program

From time to time 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 value upon which the payments are based. The related amount payable to or receivable from counterparties is included as an adjustment to accrued interest. At December 31, 2008, there were no interest related financial instruments outstanding.

Fair Value Hedges – Interest Rate Swaps

In January 2006, we entered into interest rate swap agreements with a total notional value of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate Revolving Credit Facility. Under the swap agreements, we paid a fixed rate of interest ranging from 4.67% to 4.695% and received a floating rate based on the three-month U.S. Dollar LIBOR rate. At December 31, 2007, the fair value of these interest rate swaps was an asset of $0.3 million. These interest rate swaps expired in January 2008.

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 value of $210.0 million and was set to mature in January 2028 to match the principal and maturity of the TE Products Senior Notes. During the years ended December 31, 2007 and 2006, we recognized reductions in interest expense of $0.5 million and $1.9 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. In September 2007, we terminated this 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 $1.0 million recognized in interest expense in January 2008 at the time the 7.51% Senior Notes were redeemed.

Cash Flow Hedges – Treasury Locks

At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to anticipated debt incurrence. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions was designated as a cash flow hedge under SFAS 133.

In 2007, we entered into treasury locks, accounted for as cash flow hedges, which extended through January 31, 2008 for a notional value totaling $600.0 million. At December 31, 2007, the fair value of the treasury locks was a liability of $25.3 million. In January 2008, these treasury locks were extended through April 30, 2008. In March 2008, these treasury locks were settled concurrently with the issuance of senior notes (see Note 12 in the Notes to Consolidated Financial Statements). The settlement of the treasury locks resulted in losses of $52.1 million, and these losses were recorded in accumulated other comprehensive income. We recognized approximately $3.6 million of this loss in interest expense as a result of interest payments hedged under the treasury locks not occurring as forecasted. The remaining losses are being amortized using the effective interest method as increases to future interest expense over the terms of the forecasted interest payments, which range from five to ten years. Over the next twelve months, we expect to reclassify $5.8 million of accumulated other comprehensive loss that was generated by these treasury locks as an increase to interest expense. In the event of early extinguishment of these senior notes, any remaining unamortized losses would be recognized in the statement of consolidated income at the time of extinguishment.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 6 in the Notes to Consolidated Financial Statements for information regarding fair value disclosures pertaining to our financial assets and liabilities.

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") begin on page F-1 of this Report.

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

None.

Item 9A. ***Controls and Procedures***

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 at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

Other than as discussed under "TEPPCO Marine Services Transactions" below, there were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the fourth quarter of 2008, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

TEPPCO Marine Services Transactions

On February 1, 2008, 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. (collectively, "Cenac"), the sole owner of Cenac Towing Co., Inc. and Cenac Offshore, L.L.C. On February 29, 2008, we purchased marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately-held Houston-based company and an affiliate of Mr. Cenac. These purchases were recorded using purchase accounting. In recording the TEPPCO Marine Services purchase transactions, we followed our normal accounting procedures and internal controls.

The Office of the Chief Accountant of the SEC has issued guidance regarding the reporting of internal control over financial reporting in connection with a material acquisition. This guidance was reiterated in September 2007 to affirm that management may omit an assessment of an acquired business' internal control over financial reporting from management's assessment of internal control over financial reporting for a period not to exceed one year.

We are excluding the operations acquired from Cenac and Horizon from the scope of our Sarbanes-Oxley Section 404 report on internal control over financial reporting for the year ended December 31, 2008. We are in the process of implementing our internal control structure over the operations we acquired from Cenac and Horizon. We expect this effort to be completed by mid 2009.

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 AS OF DECEMBER 31, 2008

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, 2008. 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*. As allowed by U.S. Securities and Exchange Commission ("SEC") guidance, management excluded from its assessment the operations related to the 2008 acquisitions of Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (collectively, "Cenac") and Horizon Maritime, L.L.C. ("Horizon"), which accounted for approximately 13 percent of consolidated total assets and approximately 14 percent of consolidated operating income and six percent of consolidated net income.

Based on the assessment and those criteria, management believes that the Partnership maintained effective internal control over financial reporting as of December 31, 2008. 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
Jerry E. Thompson
President and Chief Executive Officer
of our General Partner,
Texas Eastern Products Pipeline Company, LLC

/s/ TRACY E. OHMART
Tracy E. Ohmart
Acting Chief Financial Officer of our
General Partner,
Texas Eastern Products Pipeline Company, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Texas Eastern Products Pipeline Company, LLC and
Unitholders of TEPPCO Partners, L.P.
Houston, Texas

We have audited the internal control over financial reporting of TEPPCO Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2008, management excluded from its assessment the internal control over financial reporting of the operations related to the 2008 acquisitions of Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (collectively, "Cenac") and Horizon Maritime, L.L.C. ("Horizon"), which accounted for approximately 13 percent of consolidated total assets and approximately 14 percent of consolidated operating income and six percent of consolidated net income as of and for the year ended December 31, 2008. Accordingly, our audit did not include the internal control over financial reporting related to the acquired operations of Cenac and Horizon. 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 as of December 31, 2008. 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, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related statements of consolidated income, consolidated comprehensive income, consolidated cash flows, and consolidated partners' capital as of and for the year ended December 31, 2008 of the Partnership and our report dated March 2, 2009 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Houston, Texas
March 2, 2009

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 Group Co-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. Other than Patricia A. Totten, our Vice President, General Counsel and Secretary, 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 require 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 Messrs. Snell and Daigle and determined that they do not constitute material relationships that affect their 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 a family trust that owns a total of 3,000 Enterprise Products Partners common units. Mr. Snell was also the trustee of a family trust, which was terminated during 2008, that owned a total of 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.

- During 2008 the Board approved a consulting arrangement between Mr. Daigle's brother-in-law, a crude oil tank farm specialist, and the Partnership involving consulting fees not to exceed $120 thousand related to the cleaning of crude oil storage tanks. To date no services have been rendered or payments made under this consulting arrangement. The Board determined this relationship is not material because of the qualifications of Mr. Daigle's family member, the limited scope of the arrangement and the capping of potential fees.

Code of Conduct and Ethics and Corporate Governance Guidelines

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. Our Governance Guidelines are currently available on our website at www.teppco.com under Corporate Governance. Additionally, the Code of Conduct and our Corporate Governance Guidelines 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.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named four of its members to serve on its 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.

The Charter of our ACG Committee is currently available on our website at www.teppco.com under Corporate Governance. Additionally, the Charter of the ACG Committee is 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.

NYSE Corporate Governance Listing Standards

On March 6, 2008, 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 March 6, 2008, 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 of our General Partner

The following table sets forth certain information with respect to the directors and executive officers of the General Partner as of March 2, 2009.

Name	Age	Position with Our General Partner
Michael B. Bracy	67	Director, Member of Audit, Conflicts and Governance Committee*
Murray H. Hutchison	70	Chairman of the Board, Member of the Audit, Conflicts and Governance Committee
Richard S. Snell	66	Director, Member of the Audit, Conflicts and Governance Committee
Donald H. Daigle	67	Director, Member of the Audit, Conflicts and Governance Committee
Jerry E. Thompson	59	President, Chief Executive Officer and Director
Tracy E. Ohmart	41	Acting Chief Financial Officer
J. Michael Cockrell+	62	Senior Vice President, Commercial Upstream
John N. Goodpasture+	60	Vice President, Corporate Development
Samuel N. Brown+	52	Vice President, Commercial Downstream
Patricia A. Totten	58	Vice President, General Counsel and Secretary
Joel H. Kieffer	51	Vice President, Marine Services

* Chairman of committee
+ See "–Employment Arrangements and Termination or Change-in-Control Payments" 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.

Tracy E. Ohmart was appointed Acting Chief Financial Officer of the General Partner effective January 15, 2009 and serves as the principal financial and accounting officer of the General Partner. Mr. Ohmart has served as Controller of the General Partner since May 2002 and as Assistant Treasurer since February 2007, and 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 until he became Assistant Controller in May 2001.

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.

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 December 2007, Ms. Totten was elected Vice President, Assistant General Counsel, and Assistant Secretary of EPCO. Ms. Totten served as Assistant Secretary of EPCO from November 2005 to December 2007.

Joel H. Kieffer has served as Vice President, Marine Services of the General Partner since March 2008. Mr. Kieffer was previously Vice President, Refining and Terminals of CITGO Asphalt Refining Company from October 2004 to March 2008. Mr. Kieffer joined CITGO in 1981 and advanced from a process engineer in Operations Engineering to positions of increasing responsibilities in the technical, operations, logistics, commercial and corporate aspects of CITGO. He was elected general manager of Engineering and Technical Services in 1997 and General Manager of Operations and Maintenance of the Lake Charles refinery in 2001. Mr. Kieffer is a past president of Lake Charles Pipeline Company.

In addition to our Executive Officers, Mark G. Stockard, age 42, 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.

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, 2008, except for one report by Mr. Brown.

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 partnership. Instead, we are managed by our General Partner, the executive officers of which are employees of EPCO. Our reimbursement of EPCO’s compensation costs is governed by the ASA with EPCO (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, 2008 are referred to as the “Named Executive Officers” and are included in the Summary Compensation Table below.

Compensation paid or awarded by us with respect to our Named Executive Officers for the last three fiscal years reflects only that portion of compensation paid by EPCO allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO, our equity-based long-term incentive plans and awards of equity profits interests in employee partnerships described below. 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 the 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 us to attract, motivate and retain 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 incentive compensation. For the years ended December 31, 2008, 2007 and 2006, the 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;
- awards of equity profits interests in employee partnerships described below; 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 considers market data for determining relevant compensation levels and compensation program elements. The market data that has in the past and is likely to be considered in the future in assessing relevant compensation levels and compensation program elements is limited to the review of and, in some cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third party compensation consultant.

Periodically, EPCO will engage a third party consultant to review compensation elements provided to our executives. For example, in 2006, EPCO engaged Towers Perrin to review executive compensation relative to our industry. Towers Perrin provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors. Neither we nor EPCO are aware of the identity of the component companies who supplied data to the consultant. EPCO used the data provided in the Towers Perrin analysis to gauge whether compensation levels reported by the consultant were within the general ranges of compensation for EPCO employees in similar positions, but that comparison is only a factor taken into consideration and may or may not impact compensation of our executive officers. EPCO does not otherwise engage in benchmarking executive level positions.

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. Mr. Duncan and EPCO also consider individual performance, levels of responsibility, skills and experience. 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.

We believe the absence of specific performance-based criteria associated with our salary compensation and equity awards, and the long-term nature of our equity awards, has the effect of not encouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions. Because our 2008 annual base salaries and the majority of our 2008 equity awards were made in the first half of 2008, recent market volatility and market declines did not have a material impact on 2008 compensation decisions. However, current market conditions may impact 2009 compensation decisions regarding annual base salaries and equity award grants.

The discretionary cash awards paid to each of our Named Executive Officers were determined by consultation among Mr. Duncan, Mr. Thompson and the Senior Vice President of Human Resources for EPCO, subject to Mr. Duncan's final determination. These cash awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the Named 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 equity awards granted to the Named Executive Officers under the long-term incentive plans were determined as a result of consultation among Mr. Duncan and the Senior Vice President of Human Resources for EPCO and were approved by our ACG Committee. This 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.

In addition, in September 2008, EPCO began issuing profits interests to our Named Executive Officers that entitle the holders to participate in the appreciation in value of our Units in the form of Class B limited partner interests in employee partnerships. This arrangement is similar to employee partnerships EPCO formed to incentivize management of its other public company affiliates. Our Named Executive Officers were issued profits interests in TEPPCO Unit L.P. ("TEPPCO Unit"), which was formed on September 4, 2008, and TEPPCO Unit II L.P. ("TEPPCO Unit II"), which was formed on November 13, 2008, (collectively, "Employee Partnerships"). EPCO serves as the general partner of the Employee Partnerships and Mr. Duncan approves the issuance of all limited partnership interests in such Employee Partnerships to our Named Executive Officers. The profits interests are equity-based compensatory awards and are subject to forfeiture. See Note 4 in the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the accounting for such awards.

In connection with the formation of TEPPCO Unit, EPCO Holdings, Inc. ("EPCO Holdings"), an affiliate of EPCO, contributed approximately $7.0 million to TEPPCO Unit as a capital contribution with respect to its interest and was admitted as the Class A limited partner of TEPPCO Unit. TEPPCO Unit purchased 241,380 Units directly from us in an unregistered transaction at the public offering price concurrently with the closing of our September 2008 equity offering. Our Executive Officers (including each of the Named Executive Officers) were issued Class B limited partner interests and admitted as Class B limited partners of TEPPCO Unit without any capital contribution. The profits interests awards in TEPPCO Unit will vest on the earlier of (i) September 4, 2013, (ii) a change of control or (iii) dissolution of TEPPCO Unit pursuant to its partnership agreement. See "—Termination or Change in Control Payments" and "—Employee Partnership Profits Interests" below.

In connection with the formation of TEPPCO Unit II, DFI contributed to TEPPCO Unit II 123,185 Units representing limited partner interests in TEPPCO (with a value of approximately $3.1 million, based on the closing price of the Units on November 12, 2008) and was admitted as the Class A limited partner. Mr. Thompson was issued 100% of the Class B limited partner interests and admitted as Class B limited partner of TEPPCO Unit II without any capital contribution. The profits interests awards in TEPPCO Unit II will vest on the earlier of (i) November 13, 2013, (ii) a change of control or (ii) dissolution of TEPPCO Unit II pursuant to its partnership agreement. Pursuant to an amendment to the ASA, we reimburse EPCO for the amount of distributions of cash or securities, if any, made by one of EPCO's TEPPCO Unit II to Mr. Thompson.

For 2008, the Named Executive Officers were granted restricted units and unit options under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP"), which was approved by our unitholders in December 2006. The 2006 LTIP allows for various forms of equity or equity-based awards not contained in previous plans, including awards of restricted units, unit options and unit appreciation rights ("UARs"), which 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. 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. Restricted units awarded to our Named Executive Officers in 2008 vest on May 19, 2012. 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 2008 vest on May 19, 2012 and expire on December 31, 2013.

For 2007, the Named Executive Officers were granted restricted units, unit options and UARs under the 2006 LTIP. 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 December 31, 2012. During 2008, the 2007 unit option grants were amended to change their expiration date from May 22, 2017 to December 31, 2012. UARs awarded to our Named Executive Officers in 2007 vest on May 22, 2012 and expire on the same date.

For 2006, all equity 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 equity 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 Equity Awards and 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 parking expenses and expects to continue its policy of covering very limited perquisites allocable to our Named Executive Officers. EPCO also makes matching contributions under its 401(k) plan for the benefit of our Named Executive Officers in the same manner as it does for other EPCO employees.

We believe that each of the base salary, cash awards and incentive 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 Mr. Thompson, have not entered into employment agreements with EPCO.

Three of our Named Executive Officers, Messrs. Cockrell, Brown and Goodpasture, entered into employment agreements with our General Partner 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 provided that such employment agreements would automatically terminate on June 1, 2008 in exchange for certain retention payments if the officer remained employed until such date or was terminated without cause or because of a disability or death, or resigned as a result of relocation, prior to June 1, 2008. The employment agreements terminated on June 1, 2008 pursuant to the 2007 Supplements, and EPCO paid each of the three Named Executive Officers the applicable retention payment. See "– Summary Compensation Table" below for further information on the 2007 Supplements payments.

Recipients of awards under the 1999 Plan, the 2000 LTIP and the 2006 LTIP and recipients of Employee Partnership profits interest awards are entitled to payments in the event of death, disability, and in some cases retirement pursuant to those awards. See "Termination or Change in Control Payments" 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. Mr. Thompson's annual base salary for 2008 was $482,250 and his 2008 discretionary cash bonus, which was paid in February 2009, was $265,000, or 55% 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 vested 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. He received awards of restricted units, unit options and UARs in May 2007 and received awards of restricted units and unit options in May 2008. He received profit interests in TEPPCO Unit in September 2008 and profit interests in TEPPCO Unit II in November 2008. See " – Grants of Plan-Based Awards in Fiscal Year 2008" below.

Chief Financial Officer Resignation

On January 15, 2009, Mr. William Manias, the Vice President and CFO of our General Partner resigned. On January 19, 2009, EPCO, the employer of Mr. Manias, entered into an Agreement and Release with him setting forth the terms of his departure. Under such agreement, Mr. Manias received a cash payment of $1.3 million on January 31, 2009, and may be eligible to receive medical insurance coverage for a period of up to 18 months at no cost. Mr. Manias agreed to forfeit unvested grants and awards of phantom units, restricted units, UARs, options, TEPPCO Unit profit interests and any other interests under our long-term incentive plans. Also under the agreement, Mr. Manias agreed not to solicit the employment of employees, or business of clients, of EPCO or its affiliates and agreed to keep all trade secrets and proprietary and confidential information related to EPCO or any of its affiliates confidential, unless otherwise required by law.

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. 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 equity awards in accordance with SFAS 123(R), *Share-Based Payment*. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying Units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity award is amortized to earnings on a straight-line basis over the requisite service or vesting period of the equity 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

Notwithstanding 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, 2008, 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)	2008	482,250	265,000	311,200	49,626	168,378	1,276,454
President and Chief Executive Officer	2007	463,500	281,000	803,761	29,317	151,975	1,729,553
	2006	325,673	770,000	721,000	--	58,007	1,874,680
William G. Manias (2)	2008	221,025	--	29,352	24,359	75,392	350,128
Vice President and Chief Financial	2007	206,175	74,000	68,570	13,498	30,481	392,724
Officer	2006	192,825	75,000	37,059	--	49,497	354,381
J. Michael Cockrell	2008	279,130	103,000	15,965	24,451	561,040	983,586
Senior Vice President, Commercial	2007	267,750	105,500	127,784	14,437	535,029	1,050,500
Upstream	2006	255,628	98,000	119,706	--	157,611	630,945
John N. Goodpasture	2008	251,125	76,050	2,492	24,343	353,494	707,504
Vice President, Corporate Development	2007	233,375	76,000	108,965	13,342	334,865	766,547
	2006	231,737	62,000	106,792	--	107,397	507,926
Samuel N. Brown	2008	244,750	70,000	5,015	24,359	297,876	642,000
Vice President, Commercial	2007	241,500	76,000	95,244	13,498	281,958	708,200
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. Effective January 15, 2009, Mr. Manias resigned from his position as Vice President and CFO of our General Partner. See "– Employment Arrangements and Termination or Change in Control Payments" above.

(3) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Payments under the discretionary annual cash awards program are made in the subsequent year (e.g., the cash awards for 2008 were paid in February 2009).

(4) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to phantom unit awards issued under the 1999 Plan and 2000 LTIP, restricted unit awards issued under the 2006 LTIP and Employee Partnership profits interest awards issued for the years ended December 31, 2008, 2007 and 2006, respectively. The compensation amounts for the year ended December 31, 2008, are based on the following assumptions: (i) the closing price of a Unit at December 31, 2008 was $19.57; (ii) with respect to restricted units, the 2008 awards grant date closing price was $35.86 per Unit and the 2007 awards 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 69.7%; (iv) the percentage of the number of days in the period presented compared to the total vesting period; (v) with respect to the Employee Partnership awards from TEPPCO Unit, (a) expected life of option of 5 years, (b) risk-free interest rate of 2.87%; (c) expected distribution yield on Units of 7.28%; and (d) expected Unit price volatility on Units of 16.42%; and (vi) with respect to the Employee Partnership awards from TEPPCO Unit II, (a) expected life of option of 5 years, (b) risk-free interest rate of 2.37%; (c) expected distribution yield on Units of 13.87%; and (d) expected Unit price volatility on Units of 66.38%. See discussion of the equity awards and the 2008 grants from these equity incentive plans to the Named Executive Officers below.

(5) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to unit option awards and UARs issued under the 2006 LTIP for the years ended December 31, 2008 and 2007. With respect to the unit option awards granted in 2008, the compensation amounts are based on the following assumptions: (i) expected life of option of 4.7 years, (ii) risk-free interest rate of 3.3%; (iii) expected distribution yield on Units of 7.9%; and (iv) expected Unit price volatility on Units of 18.7%. With respect to the unit option awards granted in 2007, 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(v) expected Unit price volatility on Units of 18.03%. 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 for the year ended December 31, 2008, are based on the assumptions that (i) the closing price of a Unit at December 31, 2008 was $19.57; (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 2008 grants from this equity incentive plan to the Named Executive Officers below.

(6) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans; (ii) quarterly distributions paid on incentive plan awards; (iii) retention payments made; and (iv) the imputed value of life insurance premiums paid on behalf of the Named Executive Officer. Components of "All Other Compensation" for which $10,000 or more was paid to or accrued for any Named Executive Officer in 2008 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 2007 Supplements ($)	Other Compensation ($)	Total All Other Compensation ($)
Jerry E. Thompson	23,000	137,526	--	7,852	168,378
William G. Manias	23,000	48,941	--	3,451	75,392
J. Michael Cockrell	27,600	34,388	489,375	9,677	561,040
John N. Goodpasture	23,000	25,416	295,800	9,278	353,494
Samuel N. Brown	25,300	24,756	241,920	5,900	297,876

Grants of Plan-Based Awards in Fiscal Year 2008

The following table presents information concerning grants of plan-based awards to the Named Executive Officers in 2008. The restricted unit award and unit option awards granted during 2008 were under the 2006 LTIP. See "Summary of Equity Awards and Long-Term Incentive Plans of TEPPCO" below for additional information regarding the long-term incentive plans under which these awards were granted.

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Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise Or Base Price of Options Awards ($/Unit)	Grant Date Fair Value of Option Awards ($) (6)
Jerry E. Thompson:						
Restricted unit awards (1)	5/19/2008	--	21,600	--	--	642,898
Unit option awards (2)	5/19/2008	--	50,000	--	35.86	86,735
TEPPCO Unit profits interest award (3)	9/5/2008	--	--	--	--	506,398
TEPPCO Unit II profits interest award (4)	11/13/2008	--	--	--	--	1,405,748
William G. Manias: (5)						
Restricted unit awards (1)	5/19/2008	--	3,400	--	--	101,197
Unit option awards (2)	5/19/2008	--	25,000	--	35.86	43,368
TEPPCO Unit profits interest award (3)	9/5/2008	--	--	--	--	126,555
J. Michael Cockrell:						
Restricted unit awards (1)	5/19/2008	--	6,000	--	--	178,583
Unit option awards (2)	5/19/2008	--	25,000	--	35.86	43,368
TEPPCO Unit profits interest award (3)	9/5/2008	--	--	--	--	253,288
John N. Goodpasture:						
Restricted unit awards (1)	5/19/2008	--	3,400	--	--	101,197
Unit option awards (2)	5/19/2008	--	25,000	--	35.86	43,368
TEPPCO Unit profits interest award (3)	9/5/2008	--	--	--	--	253,288
Samuel N. Brown:						
Restricted unit awards (1)	5/19/2008	--	3,400	--	--	101,197
Unit option awards (2)	5/19/2008	--	25,000	--	35.86	43,368
TEPPCO Unit profits interest award (3)	9/5/2008	--	--	--	--	253,288

(1) Award of restricted units under the 2006 LTIP. The grant date fair value of restricted unit awards issued during 2008 was based on a market price of $35.86 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 2008 was based on the following assumptions: (i) expected life of option of 4.7 years, (ii) risk-free interest rate of 3.3%; (iii) expected distribution yield on Units of 7.9%; (iv) estimated forfeiture rate of 17%; and (v) expected Unit price volatility on Units of 18.7%.
(3) The fair value of TEPPCO Unit profits interest awards issued in September 2008 was based on the following assumptions: (i) remaining life of the award of five years; (ii) risk-free interest rate of 2.87%; (iii) the expected distribution yield on Units of 7.28%; and (iv) an expected Unit price volatility of Units of 16.42%.
(4) The fair value of TEPPCO Unit II profits interest awards issued in November 2008 was based on the following assumptions: (i) remaining life of the award of five years; (ii) risk-free interest rate of 2.37%; (iii) the expected distribution yield on Units of 13.87%; and (iv) an expected Unit price volatility of Units of 66.38%.
(5) Effective January 15, 2009, Mr. Manias resigned from his position as Vice President and CFO of our General Partner. See "–Employment Arrangements and Termination or Change in Control Payments" above.
(6) 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 2008, we recognized compensation expense of $0.2 million, $50 thousand, $0.1 million and $60 thousand related to grants to Named Executive Officers of restricted unit awards, the unit option awards TEPPCO Unit profits interest awards and TEPPCO Unit II profits interest awards, respectively. The remaining portion of the grant date 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 equity awards including awards under long-term incentive plans and profits interests. 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 "–Termination or Change in Control Payments" below.

Summary of Equity Awards and Long-Term Incentive Plans of TEPPCO

The following information summarizes the types of awards granted to our Named Executive Officers and outstanding as of the year ended December 31, 2008. For detailed information regarding our accounting for equity awards, see Note 4 in the Notes to Consolidated Financial Statements under Item 8 of this annual report.

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. No awards were granted with respect to the 1999 Plan during the years ended December 31, 2008 and 2007. The only award outstanding to a Named Executive Officer under the 1999 Plan is the grant of phantom units to Mr. Thompson that will vest (subject to conditions specified therein) on April 11, 2009.

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. No awards were granted with respect to the 2000 LTIP during the years ended December 31, 2008 and 2007, and after the payout in the first quarter of 2009 on awards which vested on December 31, 2008, there will be no awards to our Named Executive Officers outstanding under the 2000 LTIP.

The performance period applicable to awards granted in 2006 was the three-year period that commenced on January 1, 2006, and ended on December 31, 2008. 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 $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). The performance percentage at December 31, 2008 was 69.7%. At December 31, 2008, we had an accrued liability of $0.1 million for compensation expense related to the 2000 LTIP awards granted in 2006 that vested at December 31, 2008, for which cash will be paid to the respective Named Executive Officers in the first half of 2009. See "Option Exercises and Stock Vested Table" for amounts that will be paid to individual Named Executive Officers.

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%. In the first quarter of 2008, $0.5 million was paid to the respective Named Executive Officers related to 2000 LTIP awards granted in 2005 that vested at December 31, 2007.

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 was 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. 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 under the 2006 LTIP. 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.

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.

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.

During 2008, awards of restricted units and unit options were granted to participants, including Named Executive Officers. Restricted units awarded to our Named Executive Officers on May 19, 2008 vest on May 19, 2012. Unit options awarded to our Named Executive Officers on May 19, 2008 vest on May 19, 2012 and expire on December 31, 2013.

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 December 31, 2012. During 2008, the 2007 unit option awards were amended to change their expiration date from May 21, 2017 to December 31, 2012. UARs awarded to our Named Executive Officers in 2007 vest on May 22, 2012 and expire on the same date.

Profits interests awards

EPCO formed TEPPCO Unit and TEPPCO Unit II to serve as long-term incentive arrangements for certain employees of EPCO by providing “profits interests” in TEPPCO Unit and TEPPCO Unit II, respectively. Our Named Executive Officers were granted Class B limited partner interest awards in TEPPCO Unit (formed in September 2008). Mr. Thompson has been granted a Class B limited partner interest award in TEPPCO Unit II (formed in November 2008). The Class B limited partner interests entitle each holder to participate in the appreciation in value of our Units owned by each Employee Partnership. Such awards are subject to forfeiture. Profits interests awards in TEPPCO Unit will vest on the earlier of (i) September 4, 2013, (ii) a change of control or (iii) dissolution of TEPPCO Unit pursuant to its partnership agreement, and profits interests awards in TEPPCO Unit II will vest on the earlier of (i) November 13, 2013, (ii) a change of control or (ii) dissolution of TEPPCO Unit II pursuant to its partnership agreement. For additional information regarding TEPPCO Unit and TEPPCO Unit II, see “Employee Partnerships” in Note 4 in the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which is incorporated by reference into this Item 11.

The following table provides information regarding each Named Executive Officers’ share of such Class B limited partner interest at December 31, 2008:

Plan Name	Percentage Ownership of Class B Interests (1)	Estimated Liquidation Value To Be Received by Officer (2)
TEPPCO Unit: (3)		
Jerry E. Thompson	28.57%	$ --
William G. Manias (4)	7.14%	--
J. Michael Cockrell	14.29%	--
John Goodpasture	14.29%	--
Samuel N. Brown	14.29%	--
TEPPCO Unit II: (5)		
Jerry E. Thompson	100%	--

(1) Reflects Named Executive Officer share of profits interest at December 31, 2008.
(2) Values based on December 31, 2008 closing price of $19.57 per Unit and taking into account the terms of liquidation outlined in each award.
(3) The TEPPCO Unit Class B partnership interest had no liquidation value at December 31, 2008 due to a decrease in the market value of our Units since the formation of TEPPCO Unit.
(4) Effective January 15, 2009, Mr. Manias resigned from his position as Vice President and CFO of our General Partner. In connection with his resignation, Mr. Manias forfeited his profits interest award. See “–Employment Arrangements and Termination or Change in Control Payments” above.
(5) The TEPPCO Unit II Class B partnership interest had no liquidation value at December 31, 2008 due to a decrease in the market value of our Units since the formation of TEPPCO Unit II.

Equity Awards Outstanding at December 31, 2008

The following table presents information concerning each Named Executive Officer’s equity incentive awards outstanding at December 31, 2008.

	Option Awards			Unit Awards	
Name	**Number of Underlying Options Unexercisable (#)**	**Option Exercise Price ($/Unit)**	**Option Expiration Date**	**Number Of Units That Have Not Vested (#)**	**Market Value of Units That Have Not Vested ($) (5)**
Jerry E. Thompson:					
2008:					
Restricted units (1)	--	--	--	21,600	422,712
Unit options (1)	50,000	35.86	12/31/2013	--	--
2007:					
Restricted units (1)	--	--	--	19,000	371,830
Unit options (1)	45,000	45.35	12/31/2012	--	--
UARs (3)	66,152	45.35	5/22/2012	--	--
2006:					
Phantom units (2)	--	--	--	13,000	254,410
William G. Manias (4):					
2008:					
Restricted units	--	--	--	3,400	66,538
Unit options	25,000	35.86	12/31/2013	--	--
2007:					
Restricted units	--	--	--	3,000	58,710
Unit options	22,000	45.35	12/31/2012	--	--
UARs	26,461	45.35	5/22/2012	--	--
2006:					
Phantom units	--	--	--	2,800	54,796
J. Michael Cockrell:					
2008:					
Restricted units (1)	--	--	--	6,000	117,420
Unit options (1)	25,000	35.86	12/31/2013	--	--
2007:					
Restricted units (1)	--	--	--	4,200	82,194
Unit options (1)	22,000	45.35	12/31/2012	--	--
UARs (3)	33,076	45.35	5/22/2012	--	--
John N. Goodpasture:					
2008:					
Restricted units (1)	--	--	--	3,400	66,538
Unit options (1)	25,000	35.86	12/31/2013	--	--
2007:					
Restricted units (1)	--	--	--	3,000	58,710
Unit options (1)	22,000	45.35	12/31/2012	--	--
UARs (3)	25,358	45.35	5/22/2012	--	--

Name	Option Awards			Unit Awards	
	Number of Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number Of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($) (5)
Samuel N. Brown:					
2008:					
Restricted units (1)	--	--	--	3,400	66,538
Unit options (1)	25,000	35.86	12/31/2013	--	--
2007:					
Restricted units (1)	--	--	--	3,000	58,710
Unit options (1)	22,000	45.35	12/31/2012	--	--
UARs (3)	26,461	45.35	5/22/2012	--	--

(1) Awards granted in 2008 and 2007 vest on May 19, 2012 and May 22, 2011, respectively, 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.
(2) Phantom units vest on April 11, 2010, subject to earlier vesting on death or disability.
(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) Effective January 15, 2009, Mr. Manias resigned from his position as Vice President and CFO of our General Partner. In connection with his resignation, all of the awards listed below his name were forfeited. See "–Employment Arrangements and Termination or Change in Control Payments" above.
(5) Amount reflects the market value of the number of phantom units and restricted units at December 31, 2008 using the December 31, 2008 price of $19.57 per Unit.

The profits interest awards granted to the Named Executive Officers from TEPPCO Unit and TEPPCO Unit II had no market (or assumed liquidation) value at December 31, 2008 due to a decrease in the market value of our Units owned by TEPPCO Unit and TEPPCO Unit II since formation.

Option Exercises and Stock Vested Table

The following table presents information concerning vesting of phantom unit awards during 2008 for each of the Named Executive Officers on an aggregate basis. No options were exercised by the Named Executive Officers during 2008.

Name	Unit Awards	
	Number of Units Acquired On Vesting (#)	Value Realized On Vesting ($)
Jerry E. Thompson (1)	--	446,030
J. Michael Cockrell (2)	--	40,635
Samuel N. Brown (2)	--	35,392
John N. Goodpasture (2)	--	36,702

(1) Amount represents an April 2008 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 69.7% at December 31, 2008, for which cash will be paid out to the Named Executive Officer in March 2009.

Pension Benefits for the 2008 Fiscal Year

EPCO does not offer our Named Executive Officers a defined benefit pension plan.

Nonqualified Deferred Compensation for the 2008 Fiscal Year

During 2008, 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.

Termination or Change in Control Payments

Other than as set forth below under the headings “Business Combination with Enterprise Products Partners,” and “Employee Partnership Profits Interests,” there are currently no outstanding equity awards or employment agreements that provide for payments to a Named Executive Officer in event of any termination or change in control. The 1999 Plan 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, 2008 if specified termination events occur.

Name	Death or Disability Accelerated 1999 Plan Awards (2)	Death, Disability or Retirement Accelerated 2006 LTIP Awards (3)
Jerry E. Thompson	254,410	1,048,952
William G. Manias (1)	54,796	180,044
J. Michael Cockrell	--	148,732
Samuel N. Brown	--	125,248
John N. Goodpasture	--	125,248

(1) Effective January 15, 2009, Mr. Manias resigned from his position as Vice President and CFO of our General Partner. In connection with his resignation, his outstanding equity awards were forfeited. See “–Employment Arrangements and Termination or Change in Control Payments” above.
(2) Amount represents the market value of phantom unit awards based on a Unit price of $19.57 at December 31, 2008. Phantom units vest in full in the event of termination due to death or disability.
(3) 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 $19.57 at December 31, 2008. Unit options and UARs are assigned no market value at December 31, 2008 as a result of the grant date price exceeding the Unit price at December 31, 2008 of $19.57.

Business Combination with Enterprise Products Partners

For any awards under the 1999 Plan, 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 Mr. Thompson, the EPCO Grant will provide, to the extent that such EPCO Grant is awarded prior to April 11, 2009, that the award will vest on April 11, 2009, assuming Mr. Thompson’s continuing employment through the vesting period. The only award outstanding to a Named Executive officer under the 1999 Plan is the grant of phantom units to Mr. Thompson that will vest (subject to conditions specified therein) on April 11, 2009. The EPCO Grant 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.

Employee Partnership Profits Interests

Awards of Employee Partnership profits interests vest in full upon a change of control, as defined in the partnership agreements of the respective Employee Partnerships, assuming the individual's continued employment through the vesting period or an earlier qualifying termination. "Change of Control" with respect to TEPPCO Unit means Mr. Dan Duncan shall (i) cease to own, directly or indirectly, at least a majority of the equity interests in the general partner of TEPPCO Unit or the general partner of EPE, or (ii) shall cease to have the ability to elect, directly or indirectly, at least a majority of the directors of our General Partner. "Change of Control" with respect to TEPPCO Unit II means Mr. Dan Duncan shall (i) cease to own, directly or indirectly, at least a majority of the equity interests in the general partner of TEPPCO Unit II or our General Partner or (ii) shall cease to have the ability to elect, directly or indirectly, at least a majority of the directors of our General Partner. "Qualifying Termination" with respect to both Employee Partnerships means termination of employment due to (i) death, (ii) receiving long-term disability benefits under the long-term disability plan of the general partner of the Employee Partnership or any of its affiliates or (iii) retirement with the approval of the general partner of the Employee Partnership on or after reaching age 60. A Qualifying Termination will not accelerate vesting of Employee Partnership profits interest awards.

Director Compensation

The following table presents information regarding compensation to the non-management directors of our General Partner for the year ended December 31, 2008. Our General Partner is responsible for compensating these directors for their services.

Director	Fees Earned or Paid in Cash ($)	Unit Awards ($)(3)	Option Awards ($)(4)	All Other Compensation ($)(5)	Total ($)
Michael B. Bracy (1)	90,000	969	165	1,559	92,693
Murray H. Hutchison (2)	90,000	969	165	1,559	92,693
Richard S. Snell	75,000	969	165	1,559	77,693
Donald H. Daigle	75,000	--	1,701	--	76,701

(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 to Mr. Bracy, Mr. Hutchison and Mr. Snell during 2008 and 2007 under the 2006 LTIP (see "– Equity-based compensation" below). On April 30, 2007, Mr. Bracy, Mr. Hutchison and Mr. Snell were each awarded 549 phantom units, all of which were outstanding at December 31, 2008. 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 at December 31, 2008 was $19.57 per Unit; (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, 2008, the fair value of phantom units granted to each of Mr. Bracy, Mr. Snell and Mr. Hutchison was $10,744.
(4) Amount presented reflects the compensation expense recognized related to UARs granted to Mr. Bracy, Mr. Hutchison and Mr. Snell during 2007 and to Mr. Daigle during 2008 under the 2006 LTIP (see "– Equity-based compensation" below). On May 2, 2007, Mr. Bracy, Mr. Hutchison and Mr. Snell were each awarded 22,075 UARs, all of which were outstanding at December 31, 2008. On June 20, 2008, Mr. Daigle was awarded 29,429 UARs, all of which were outstanding at December 31, 2008. 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 at December 31, 2008 was $19.57 per Unit; and (ii) the payout percentage is 100%. At December 31, 2008, the fair value of UARs granted to each of Mr. Bracy, Mr. Snell and Mr. Hutchison, was $2,306 and the fair value of UARs awarded to Mr. Daigle was $10,320.
(5) Amounts primarily represent quarterly distributions payable on account of phantom unit awards. Mr. Hutchison and Mr. Snell did not receive the November 2008 quarterly distribution payment. The amount was subsequently paid in January 2009.

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, 2008, our standard compensation arrangement for non-employee directors was that each director received $75,000 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.

Equity-Based Compensation

On April 30, 2007, Mr. Bracy, Mr. Hutchison and Mr. Snell 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, Mr. Bracy, Mr. Hutchison and Mr. Snell will each 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 Mr. Bracy, Mr. Hutchison and Mr. Snell are accounted for similar to SFAS 123(R) liability awards.

On May 2, 2007, Mr. Bracy, Mr. Hutchison and Mr. Snell were each awarded 22,075 UARs under the 2006 LTIP. The grant date price of the May 2007 UARs was $45.30 per Unit. On June 20, 2008, Mr. Daigle was awarded 29,429 UARs under the 2006 LTIP. The grant date price of the June 2008 UARs was $33.98 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. ***Security 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 January 31, 2009, 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 is based on information provided to us by Mr. Duncan's representatives.

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	8.6%
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	2.4%
Units owned by EPE Holdings, LLC: (9)		
Units owned by Enterprise GP Holdings L.P.	4,400,000	4.2%
Units owned by TEPPCO Unit and TEPPCO Unit II (10)	364,565	*
Units owned directly	64,200	*
Total for Dan L. Duncan	17,073,315	16.3%

(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) As a result of EPCO's ownership of the general partner of each TEPPCO Unit and TEPPCO Unit II, Mr. Duncan is deemed beneficial owner of the securities held by these entities.

Security Ownership of Management

The following table sets forth certain information, as of February 2, 2009, 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	1,000	*
Donald H. Daigle	--	--
Jerry E. Thompson	70,760	*
William G. Manias (3)	2,000	*
Samuel N. Brown	7,400	*
J. Michael Cockrell	15,200	*
John N. Goodpasture	8,400	*
Tracy E. Ohmart	1,900	*
All directors and current executive officers (consisting of 11 people)	137,877	*

(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.
(3) Effective January 15, 2009, Mr. Manias resigned from his position as Vice President and CFO of our General Partner. In connection with his resignation, his outstanding equity awards were forfeited. See "Compensation Discussion and Analysis - Employment Arrangements and Terminations or Change in Control Payments" in Item 11 above.

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 December 31, 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)	355,000	$ 40.00	4,487,084
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	355,000	$ 40.00	4,487,084

(1) Of the 355,000 unit options outstanding at December 31, 2008, 47,000 unit options were forfeited on January 15, 2009 related to the resignation of our Chief Financial Officer. See Item 11 for additional information. After adjusting for this forfeiture 133,000 of the remaining unit options are exercisable in 2011 and 175,000 are exercisable in 2012. 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 2008, a total of 96,900 restricted unit awards were issued to key employees of EPCO, and at December 31, 2008, 157,300 restricted unit awards remain outstanding. Of the restricted units outstanding at December 31, 2008, 6,400 restricted units were forfeited on January15, 2009, related to the resignation of our Chief Financial Officer. For additional information regarding the 2006 LTIP and related equity awards, see Note 4 in the Notes to Consolidated Financial Statements.

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

The following information summarizes our business relationships and transactions with related persons, including EPCO and other affiliates, controlled by Dan L. Duncan, during the year ended December 31, 2008. We have also provided information regarding our business relationships and transactions with our unconsolidated affiliates and Cenac, which held over 5% of our Units from February 2008 until September 9, 2008, when its ownership was reduced below 5% as a result of our equity offering. We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. 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:

	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, 2008 distributions paid to the General Partner totaled $54.9 million, including incentive distributions of $49.4 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;
§ Enterprise Gas Processing, LLC, which is controlled by affiliates of EPCO and is our joint venture partner in Jonah;
§ Enterprise Offshore Port System, LLC, which is controlled by affiliates of EPCO and is one of our joint venture partners in Texas Offshore Port System; and
§ TEPPCO Unit and TEPPCO Unit II, which are controlled by EPCO.

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 $54.9 million and $48.3 million during the years ended December 31, 2008 and 2007, 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.

Administrative Services Agreement

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 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 (all 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, 2008, 2007 and 2006 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, 2008, 2007 and 2006 include amounts we reimburse to EPCO for administrative services, including compensation of employees. We also reimburse EPCO for the amount of distributions of cash or securities, if any, made by TEPPCO Unit II to Mr. Thompson. 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).

Since the vast majority of such expenses are charged to us on an actual basis (i.e. no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a stand-alone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a stand-alone basis.

EPCO and its affiliates have no obligation to present business opportunities to us or our subsidiaries, and we and our subsidiaries 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 January 30, 2009, we entered into the Fifth Amended and Restated ASA, which amended the previous ASA to provide for the cash reimbursement to EPCO by us of distributions of cash or securities, if any, made by TEPPCO Unit II to its Class B limited partner, Mr. Thompson, our Chief Executive Officer and an employee of EPCO. The Fifth Amended and Restated ASA also extended the term of EPCO's service obligations from December 2010 to December 2013 and made other updating and conforming changes. The ACG Committee approved the Fifth Amended and Restated ASA.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of our Units. For information regarding the Employee Partnerships, see “Employee Partnerships” in Note 4 in the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which is incorporated by reference into this Item 13.

Transactions between EPCO and affiliates and us

The following table summarizes related party transactions between EPCO and affiliates and us during the year ended December 31, 2008 (in thousands):

Revenues from EPCO and affiliates:		
Sales of petroleum products (1)	$	715
Transportation – NGLs (2)		13,785
Transportation – LPGs (3)		8,735
Other operating revenues (4)		13,318
Costs and Expenses from EPCO and affiliates:		
Purchases of petroleum products (5)		132,624
Operating expense (6)		104,878
General and administrative (7)		31,601

(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 $8.7 million from Enterprise Products Partners and certain of its subsidiaries.
(4) Includes sales of product inventory from TE Products to Enterprise Products Partners and 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 petroleum products 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, 2008 related to premiums paid by EPCO of $10.4 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, 2008 (in thousands):

Accounts receivable, related party (1)	$	11,011
Accounts payable, related party (2)		5,388

(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.

In December 2008, we entered into a lease agreement with Seminole Pipeline Company (“Seminole”) and Mid-America Pipeline Company, LLC, (MAPL) for the use of excess capacity on the Seminole pipeline system, a pipeline extending from Hobbs, New Mexico to Mont Belvieu, Texas. For Chaparral to use the excess capacity on Seminole, it must also access a segment of the MAPL pipeline as well. The primary term of this lease expired on January 31, 2009, and will continue on a month-to-month basis. Seminole and MAPL are subsidiaries of Enterprise Products Partners.

Jonah Joint Venture

Enterprise Products Partners (through an affiliate) is our joint venture partner in Jonah, the partnership through which we have owned our interest in the system serving the Jonah and Pinedale fields. 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, 2008, we have reimbursed Enterprise Products Partners $306.5 million ($44.9 million in 2008, $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, 2008 and 2007, we had payables to Enterprise Products Partners for costs incurred of $1.0 million and $9.9 million, respectively. At December 31, 2008 and 2007, we had receivables from Jonah of $4.7 million and $6.0 million, respectively, for operating expenses. During the years ended December 31, 2008, 2007 and 2006, we received distributions from Jonah of $132.2 million, $100.0 million and $0, respectively. The 2007 amount included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the years ended December 31, 2008, 2007 and 2006, we invested $129.8 million, $187.5 million and $121.0 million, respectively, in Jonah. During the years ended December 31, 2008, 2007 and 2006, Jonah paid distributions of $31.7 million, $9.5 million and $0, respectively, to the affiliate of Enterprise Products Partners that is our joint venture partner. Additionally, during the year ended December 31, 2008, Jonah's revenues included approximately $38.3 million of natural gas sales primarily to Enterprise Products Operating LLC, a subsidiary of Enterprise Products Partners. 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-Pinedale 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-Pinedale 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.

Texas Offshore Port System Joint Venture

Enterprise Products Partners (through an affiliate) is one of our joint venture partners in Texas Offshore Port System which was formed in August 2008 to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. We, Enterprise Products Partners and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. A subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. We and an affiliate of Enterprise Products Partners have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. Through December 31, 2008, we have invested $36.0 million in Texas Offshore Port System. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2010 and 2011.

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 17,073,315 of our Units.

Concurrently with the acquisition of our General Partner, Enterprise GP Holdings acquired non-controlling ownership interests, accounted for as equity method investments, in Energy Transfer Equity, L.P. ("Energy Transfer Equity") and LE GP, LLC, the general partner of Energy Transfer Equity.

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 $444.7 million, consisting of approximately $258.2 million in cash and approximately 4.85 million newly issued Units, representing approximately 5% of our Units outstanding at that time. Additionally, we assumed $63.2 million of Cenac's long-term debt. For additional information regarding our marine services business, please refer to "Items 1 and 2. Business Properties—Marine Services Segment—Barge Transportation of Petroleum Products." In connection with the acquisition, we entered into a transitional operating agreement with the Cenac Sellers under which they operate the purchased assets. We are obligated to indemnify the Cenac Sellers for third party claims and damages that arise from their operation of the purchased assets, unless such claims or damages arise from their gross negligence or willful misconduct or other specified exceptions apply.

On February 29, 2008, we purchased an additional 7 tow boats, 17 tank barges, rights to two tow boats under construction and certain related commercial and other agreements or the economic benefits associated therewith from Horizon Maritime, L.L.C. ("Horizon") for approximately $87 million in cash. Mr. Cenac owned 51% of the common membership interests in Horizon as well as an additional class of membership interests, and controlled Horizon. The marine vessels acquired in this transaction are also operated by Cenac under the transitional operating agreement.

We also purchased an additional 7 tank barges from Cenac and affiliates during 2008 for approximately $21.9 million in cash. These vessels are operated by Cenac under the transitional operating agreement.

The transitional operating agreement provides that we pay the Cenac Sellers a service fee of $0.5 million per year and reimburse them for their cost of providing services under the agreement. In 2008, we paid the Cenac Sellers $48.3 million in reimbursement of their costs under the agreement including the $0.5 million annual fee.

Review and Approval of Transactions with Related Parties

We generally consider transactions between us and our subsidiaries, on the one hand, and our executive officers and directors (or their immediate family members), our General Partner or its affiliates (including companies owned or controlled by Mr. Duncan such as EPCO), on the other hand, to be related party transactions. 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 addition, our ACG Committee Charter, our General Partner's written internal review and approval policies and procedures, or "management authorization policy," and the amended and restated administrative services agreement with EPCO ("ASA") govern specified related party transactions, as further described below.

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, without regard to the size of the transaction;
§ 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.

As discussed in more detail in "Item 10. Directors, Executive Officers and Corporate Governance —Partnership Management", "—Corporate Governance" and "—ACG Committee," the ACG Committee is comprised of 4 directors: Michael B. Bracy (Chairman), Murray H. Hutchison, Richard S. Snell and Donald H. Daigle. During the year ended December 31, 2008, there was one related party transaction that the ACG Committee reviewed and approved. On May 19, 2008, the ACG Committee reviewed and approved entering into the Texas Offshore Port System joint venture.

Our management authorization policy currently requires board approval for the following types of transactions to the extent such transactions have a value in excess of $15 million (thus triggering ACG Committee review under our ACG Committee Charter if such transaction is also a related party transaction):

- § asset purchase or sale transactions;
- § capital expenditures; and
- § purchase orders and operating and administrative expenses not governed by the ASA.

The ASA governs numerous day-to-day transactions between us and our subsidiaries, our General Partner 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, without mark-up or discount, 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, are subject to the management authorization policy. This policy, which applies to related party transactions as well as transactions with unrelated parties, specifies thresholds for our General Partner's officers and Chairman of the Board to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for ACG Committee Review

Under our Partnership Agreement, unless otherwise expressly provided therein or in the partnership agreements or limited liability company agreements of our subsidiaries, 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 limited liability company 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 ACG 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 and Cenac

The following table summarizes the related party transactions between Centennial, Seaway, Jonah, Texas Offshore Port System and Cenac on one hand and us, on the other hand, during the year ended December 31, 2008 (in thousands):

	For Year Ended December 31, 2008
Revenues from unconsolidated affiliates:	
Other operating revenues (1)	$ 91
Costs and Expenses from unconsolidated affiliates:	
Purchases of petroleum products (2)	7,143
Operating expense (3)	7,926
Costs and Expenses from Cenac:	
Operating expense (4)	45,382
General and administrative expense (5)	2,912

(1) Includes management fees and rental revenues.
(2) Includes pipeline transportation expense.
(3) Includes rental expense and other operating expense.
(4) Includes reimbursement for operating payroll, payroll related expenses, certain repairs and maintenance expenses and insurance premiums on our equipment.

(5) Includes reimbursement for administrative payroll and payroll related expenses, as well as payment of a $42 thousand monthly service fee and a 5% overhead fee charged on direct costs incurred by Cenac to operate the marine assets in accordance with the transitional operating agreement with Cenac.

The following table summarizes the related party balances with Centennial, Seaway, Jonah, Texas Offshore Port System and Cenac at December 31, 2008 (in thousands):

	December 31, 2008
Accounts receivable, related parties (1)	$ 4,747
Accounts payable, related parties (2)	11,831

(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, advances from Seaway for operating expenses and $3.4 million related to operational charges from Cenac.

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 "—ACG Committee", which are incorporated into this item by reference.

Item 14. *Principal Accounting Fees and Services*

Appointment of Independent Registered Public Accountant

The following table summarizes fees we paid Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31,	
Type of Fee	2008	2007
Audit Fees (1)	$ 2,679	$ 1,947
Audit Related Fees (2)	--	--
Tax Fees (3)	476	264
All Other Fees (4)	--	--
Total	$ 3,155	$ 2,211

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.
(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and partnership tax planning. In 2008, PricewaterhouseCoopers International Limited was engaged to perform the majority of tax related 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 29, 2008, the ACG Committee pre-approved Deloitte & Touche and all related fees to conduct the audit of our financial statements for the year ended December 31, 2008.

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 and 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: Consolidated Financial Statements of Jonah Gas Gathering Company and Subsidiary as of and for the years ended December 31, 2008, 2007 and 2006.

(3) Exhibits. The agreements included as exhibits are included only to provide information to investors regarding their terms. The agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and such agreements should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

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	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).
3.4	Amendment No. 2 to the Fourth Amended and Restated Agreement of Limited Partnership of TEPPCO Partners, L.P., dated as of November 6, 2008 (Filed as Exhibit 3.5 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2008 and incorporated herein by reference).
3.5	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).
3.6	First Amendment to the Amended and Restated Limited Liability Company Agreement of Texas Eastern Products Pipeline Company, LLC, dated as of November 6, 2008 (Filed as Exhibit 3.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2008 and incorporated herein by reference).
4.1	Form of Certificate representing Limited Partner Units (Filed as Exhibit 4.4 to the Form S-3 of TEPPCO Partners, L.P. filed on September 3, 2008 (Commission File No. 1-10403) and incorporated herein by reference).
4.2	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).
4.3	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).
4.4	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).

4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).
4.10	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).
4.11	Fifth Supplemental Indenture, dated as of March 27, 2008, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC, and Val Verde Gathering Company, L.P., as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.11 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
4.12	Sixth Supplemental Indenture, dated as of March 27, 2008, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.12 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
4.13	Seventh Supplemental Indenture, dated as of March 27, 2008, by and among TEPPCO Partners, L.P., as issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as subsidiary guarantors, and U.S. Bank National Association, as trustee (Filed as Exhibit 4.13 to Form

	10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
4.14	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).
10.1+	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).
10.2+	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).
10.3+	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 dated as of January 12, 2007 (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).
10.4	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).
10.5	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).
10.6+	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).
10.7+	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).
10.8+	Texas Eastern Products Pipeline Company Phantom Unit Retention Plan (1999 PURP), 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).
10.9+*	First Amendment to the Texas Eastern Products Pipeline Company, LLC Phantom Unit Retention Plan (1999 PURP), effective as of November 3, 2008.
10.10+*	First Amendment to the Texas Eastern Products Pipeline Company, LLC Phantom Unit Retention Plan (1999 PURP) Award Agreement, effective as of November 3, 2008.
10.11+	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).
10.12+	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).
10.13+*	Amendment to the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan, dated as of December 15, 2008.

10.14+	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).
10.15+	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).
10.16+	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).
10.17+*	First Amendment to the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan, dated as of December 15, 2008.
10.18+	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).
10.19+	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).
10.20+	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).
10.21+	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).
10.22+	EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit B to the definitive proxy statement on Schedule 14A of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on September 11, 2006 and incorporated herein by reference).
10.23+	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).
10.24+	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).
10.25+	Form of Phantom Unit Grant for Directors, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 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).
10.26+	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).
10.27+	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).
10.28+	Form of Distribution Equivalent Rights Grant of Texas Eastern Products Pipeline Company, LLC, under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as

	Exhibit 10.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended September 30, 2008 and incorporated herein by reference).
10.29+	Form of TPP Employee Unit Option Grant under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan (Filed as Exhibit 10.7 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
10.30+	Form of TPP Employee Amendment to Unit Option Grant under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan for options granted between April 2007 and April 2008 (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, 2008 and incorporated herein by reference).
10.31+*	Form of TPP Employee Unit Appreciation Right Grant, as amended, of Texas Eastern Products Pipeline Company, LLC under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan.
10.32	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).
10.33	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).
10.34	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).
10.35	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).
10.36	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).
10.37	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).
10.38	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).
10.39	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).
10.40	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).
10.41	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).
10.42	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).
10.43	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 March 1, 2005 and incorporated herein by reference).
10.44	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 15, 2005 and incorporated herein by reference).
10.45	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).
10.46	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).
10.47	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).
10.48	Sixth Amendment to Amended and Restated Credit Agreement, dated as of July 1, 2008, 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 Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended June 30, 2008 and incorporated herein by reference).
10.49	Supplement and Joinder Agreement dated as of July 17, 2008 of the Amended and Restated Credit Agreement dated as of October 21, 2004, among TEPPCO Partners, L.P., as Borrower, the banks and other financial institutions party thereto and SunTrust Bank, as the Administrative Agent for the Lenders (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, 2008 and incorporated herein by reference).

10.50	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).
10.51	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).
10.52	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).
10.53	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).
10.54	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).
10.55	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).
10.56+	Unit Purchase Agreement dated September 4, 2008 by and between TEPPCO Unit L.P. and TEPPCO Partners, L.P. (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on September 9, 2008 and incorporated herein by reference).
10.57+	Agreement of Limited Partnership of TEPPCO Unit L.P., dated September 4, 2008 (Filed as Exhibit 10.2 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on September 9, 2008 and incorporated herein by reference).
10.58	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).
10.59	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).
10.60	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).
10.61	Asset Purchase Agreement, dated February 29, 2008, by and among TEPPCO Marine Services, LLC, Horizon Maritime, L.L.C., Mr. Arlen B. Cenac, Jr., Mr. Steven G. Proehl, Mr. John P. Binion, Mr. Richard M. Seale and CHO, LLC (Filed as Exhibit 10 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed March 6, 2008 and incorporated herein by reference).
10.62	Amendment No. 1, dated February 29, 2008, to Asset Purchase Agreement, dated February 1, 2008, by and among TEPPCO Marine Serivces, LLC, TEPPCO Partners, L.P., Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (Filed

	as Exhibit 10.5 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
10.63	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).
10.64	Amendment No. 1, dated February 29, 2008, to Transitional Operating Agreement, dated February 1, 2008, by and among Cenac Towing Co., Inc., Cenac Offshore, L.L.C., Mr. Arlen B. Cenac, Jr., and TEPPCO Marine Serivces, LLC (Filed as Exhibit 10.6 to Form 10-Q of TEPPCO Partners, L.P. (Commission File No. 1-10403) for the quarter ended March 31, 2008 and incorporated herein by reference).
10.65	Partnership Agreement of Texas Offshore Port System, dated as of August 14, 2008 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on August 20, 2008 and incorporated herein by reference).
10.66+	Agreement of Limited Partnership of TEPPCO Unit II L.P., dated November 13, 2008 (Filed as Exhibit 10.1 to Current Report on Form 8-K of TEPPCO Partners, L.P. (Commission File No. 1-10403) filed on November 19, 2008 and incorporated herein by reference).
10.67	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).
10.68	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).
10.69	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).
10.70	Fifth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2009 (Filed as Exhibit 10.1 to Current Report on Form 8-K of Enterprise Products Partners L.P. (Commission File No. 1-14323) filed on February 5, 2009 and incorporated herein by reference).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
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.
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.

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.

Date: March 2, 2009

By: /s/ JERRY E. THOMPSON
Jerry E. Thompson,
President and Chief Executive Officer of
Texas Eastern Products Pipeline Company, LLC, General Partner

Date: March 2, 2009

By: /s/ TRACY E. OHMART
Tracy E. Ohmart,
Acting 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)	March 2, 2009
/s/ TRACY E. OHMART Tracy E. Ohmart	Acting Chief Financial Officer of Texas Eastern Products Pipeline Company, LLC (Principal Financial and Accounting Officer)	March 2, 2009
MICHAEL B. BRACY* Michael B. Bracy	Director of Texas Eastern Products Pipeline Company, LLC	March 2, 2009
RICHARD S. SNELL* Richard S. Snell	Director of Texas Eastern Products Pipeline Company, LLC	March 2, 2009
MURRAY H. HUTCHISON* Murray H. Hutchison	Chairman of the Board of Texas Eastern Products Pipeline Company, LLC	March 2, 2009
DONALD H. DAIGLE* Donald H. Daigle	Director of Texas Eastern Products Pipeline Company, LLC	March 2, 2009

* Signed on behalf of the Registrant and each of these persons pursuant to Powers of Attorney filed as Exhibit 24:

By: /s/ TRACY E. OHMART
(Tracy E. Ohmart, Attorney-in-fact)

TEPPCO PARTNERS, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Texas Eastern Products Pipeline Company, LLC and
Unitholders of TEPPCO Partners, L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2008 and 2007, and the related statements of consolidated income, comprehensive income, cash flows and partners' capital for each of the three years in the period ended December 31, 2008. These 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 March 2, 2009 expressed an unqualified opinion on the Partnership's internal control over financial reporting and did not include the internal control over financial reporting related to the acquired operations of Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. and Horizon Maritime, L.L.C.

/s/ Deloitte & Touche LLP

Houston, Texas
March 2, 2009

TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 28	$ 23
Accounts receivable, trade (net of allowance for doubtful accounts of $2,559 and $125)	790,374	1,381,871
Accounts receivable, related parties	15,758	6,525
Inventories	52,906	80,299
Other	48,496	47,271
Total current assets	907,562	1,515,989
Property, plant and equipment, at cost (net of accumulated depreciation of $678,784 and $582,225)	2,439,910	1,793,634
Equity investments	1,255,923	1,146,995
Intangible assets (net of accumulated amortization of $158,391 and $130,094)	207,653	164,681
Goodwill	106,611	15,506
Other assets	132,161	113,252
Total assets	$ 5,049,820	$ 4,750,057
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Senior notes	$ --	$ 353,976
Accounts payable and accrued liabilities	792,469	1,413,447
Accounts payable, related parties	17,219	38,980
Accrued interest	36,401	35,491
Other accrued taxes	23,038	20,483
Other	30,869	84,848
Total current liabilities	899,996	1,947,225
Long-term debt:		
Senior notes	1,713,291	721,545
Junior subordinated notes	299,574	299,538
Other long-term debt	516,654	490,000
Total long-term debt	2,529,519	1,511,083
Other liabilities and deferred credits	28,826	27,122
Commitments and contingencies		
Partners' capital:		
Limited partners' interests:		
Limited partner units (104,547,561 and 89,849,132 units outstanding)	1,746,210	1,394,812
Restricted limited partner units (157,300 and 62,400 units outstanding)	1,373	338
General partner's interest	(110,309)	(87,966)
Accumulated other comprehensive loss	(45,795)	(42,557)
Total partners' capital	1,591,479	1,264,627
Total liabilities and partners' capital	$ 5,049,820	$ 4,750,057

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2008	**2007**	**2006**
Operating revenues:			
Sales of petroleum products	$ 12,840,649	$ 9,147,104	$ 9,080,516
Transportation – Refined products	164,120	170,231	152,552
Transportation – LPGs	105,419	101,076	89,315
Transportation – Crude oil	57,305	45,952	38,822
Transportation – NGLs	52,192	46,542	43,838
Transportation – Marine	164,265	--	--
Gathering – Natural gas	57,097	61,634	123,933
Other	91,842	85,521	78,509
Total operating revenues	13,532,889	9,658,060	9,607,485
Costs and expenses:			
Purchases of petroleum products	12,703,534	9,017,109	8,967,062
Operating expense	285,760	191,697	203,015
Operating fuel and power	99,079	61,458	57,450
General and administrative	41,364	33,657	31,348
Depreciation and amortization	126,329	105,225	108,252
Taxes – other than income taxes	23,401	18,012	17,983
(Gains) losses on sales of assets	2	(18,653)	(7,404)
Total costs and expenses	13,279,469	9,408,505	9,377,706
Operating income	253,420	249,555	229,779
Other income (expense):			
Interest expense – net	(139,988)	(101,223)	(86,171)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	--	59,628	--
Equity earnings	82,693	68,755	36,761
Interest income	1,091	1,676	2,077
Other income	953	1,346	888
Income before provision for income taxes	198,169	279,737	183,334
Provision for income taxes	4,617	557	652
Income from continuing operations	193,552	279,180	182,682
Income from discontinued operations	--	--	1,497
Gain on sale of discontinued operations	--	--	17,872
Discontinued operations	--	--	19,369
Net income	$ 193,552	$ 279,180	$ 202,051

TEPPCO PARTNERS, L.P.

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

	For Year Ended December 31, 2008	2007	2006
Net Income Allocation:			
Limited Partners:			
Income from continuing operations	$ 160,969	$ 233,193	$ 130,483
Income from discontinued operations	--	--	13,835
Total Limited Partner's interest in net income	160,969	233,193	144,318
General Partner:			
Income from continuing operations	32,583	45,987	52,199
Income from discontinued operations	--	--	5,534
Total General Partner's interest in net income	32,583	45,987	57,733
Total net income allocated	$ 193,552	$ 279,180	$ 202,051
Basic and diluted net income per Limited Partner Unit:			
Continuing operations	$ 1.65	$ 2.60	$ 1.77
Discontinued operations	--	--	0.19
Basic and diluted net income per Limited Partner Unit	$ 1.65	$ 2.60	$ 1.96
Weighted average Limited Partner Units outstanding	97,530	89,850	73,657

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2008	2007	2006
Net income	$ 193,552	$ 279,180	$ 202,051
Other comprehensive income (loss):			
Cash flow hedges:			
Change in fair values of interest rate and treasury lock financial instruments	(26,802)	(23,604)	(248)
Reclassification adjustment for (gain) loss included in net income related to interest rate and treasury lock financial instruments	4,923	(64)	--
Changes in fair values of crude oil financial instruments	(19,257)	(21,036)	991
Reclassification adjustment for (gain) loss included in net income related to crude oil financial instruments	37,898	1,654	(261)
Changes in plan assets and projected benefit obligation	--	(67)	--
Total cash flow hedges	(3,238)	(43,117)	482
Total other comprehensive income (loss)	(3,238)	(43,117)	482
Comprehensive income	$ 190,314	$ 236,063	$ 202,533

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31, 2008	2007	2006
Operating activities:			
Net income	$ 193,552	$ 279,180	$ 202,051
Adjustments to reconcile net income to cash provided by continuing operating activities:			
Income from discontinued operations	--	--	(19,369)
Deferred income tax provision	36	(679)	652
Depreciation and amortization	126,329	105,225	108,252
Amortization of deferred compensation	993	830	--
Amortization in interest expense	2,224	(2,762)	(2,798)
Changes in fair market value of financial instruments	(258)	198	143
Earnings in equity investments	(82,693)	(68,755)	(36,761)
Distributions from equity investments	146,095	122,900	63,483
(Gains) losses on sales of assets	2	(18,653)	(7,404)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	--	(59,628)	--
Loss on early extinguishment of debt	8,689	1,356	--
Net effect of changes in operating accounts	(48,108)	(8,640)	(36,697)
Net cash provided by continuing operating activities	346,861	350,572	271,552
Net cash provided by discontinued operations	--	--	1,521
Net cash provided by operating activities	346,861	350,572	273,073
Investing activities:			
Proceeds from sales of assets	--	27,784	51,558
Proceeds from sale of ownership interest	--	137,326	--
Purchase of assets	--	(12,909)	(4,771)
Cash used for business combinations	(351,327)	--	(15,702)
Investment in Mont Belvieu Storage Partners, L.P.	--	--	(4,767)
Investment in Centennial Pipeline LLC	--	(11,081)	(2,500)
Investment in Jonah Gas Gathering Company	(129,759)	(187,547)	(121,035)
Investment in Texas Offshore Port System	(35,953)	--	--
Acquisition of intangible assets	(694)	(3,283)	--
Cash paid for linefill on assets owned	(12,784)	(39,418)	(6,453)
Capital expenditures	(300,503)	(228,272)	(170,046)
Net cash used in investing activities	(831,020)	(317,400)	(273,716)
Financing activities:			
Proceeds from term credit facility	1,000,000	--	--
Repayments on term credit facility	(1,000,000)	--	--
Proceeds from revolving credit facility	2,508,089	1,305,750	924,125
Repayments on revolving credit facility	(2,481,436)	(1,305,750)	(840,025)
Repayment of debt assumed in Cenac acquisition	(63,157)	--	--
Redemption of 7.51% TE Products Senior Notes	(181,571)	(36,138)	--
Repayment of 6.45% TE Products Senior Notes	(180,000)	--	--
Issuance of Limited Partner Units, net	275,856	1,696	195,060
Issuance of senior notes	996,349	--	--
Issuance of junior subordinated notes	--	299,517	--
Debt issuance costs	(9,862)	(4,052)	--
Settlement of treasury lock agreements	(52,098)	1,443	--
Payment for termination of interest rate swap	--	(1,235)	--
Acquisition of treasury units	(9)	--	--
Distributions paid	(327,997)	(294,450)	(278,566)
Net cash provided by (used in) financing activities	484,164	(33,219)	594
Net change in cash and cash equivalents	5	(47)	(49)
Cash and cash equivalents, January 1	23	70	119
Cash and cash equivalents, December 31	$ 28	$ 23	$ 70

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

STATEMENTS OF CONSOLIDATED PARTNERS' CAPITAL
(Dollars in thousands)

	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive (Loss) Income	Total
Balance, December 31, 2005	$ (61,487)	$ 1,262,846	$ 11	$ 1,201,370
Net proceeds from issuance of Limited Partner Units	--	195,060	--	195,060
Net income allocation	57,733	144,318	--	202,051
Cash distributions	(81,901)	(196,665)	--	(278,566)
Changes in fair values of crude oil financial instruments	--	--	991	991
Reclassification adjustment for gain included in net income related to crude oil financial instruments	--	--	(261)	(261)
Changes in fair values of interest rate and treasury lock financial instruments	--	--	(248)	(248)
Adjustment to initially apply SFAS 158	--	--	(67)	(67)
Balance, December 31, 2006	(85,655)	1,405,559	426	1,320,330
Net proceeds from issuance of Limited Partner Units in connection with Employee Unit Purchase Plan	--	180	--	180
Net proceeds from issuance of Limited Partner Units in connection with Distribution Reinvestment Plan	--	1,516	--	1,516
Net income allocation	45,987	233,193	--	279,180
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 financial instruments	--	--	(21,036)	(21,036)
Reclassification adjustment for loss included in net income related to crude oil financial instruments	--	--	1,654	1,654
Changes in fair values of interest rate and treasury lock financial instruments	--	--	(23,604)	(23,604)
Reclassification adjustment for gain included in net income related to interest rate and treasury lock financial instruments	--	--	(64)	(64)
SFAS 158 pension benefit adjustment	--	--	67	67
Balance, December 31, 2007	(87,966)	1,395,150	(42,557)	1,264,627
Issuance of units in connection with Cenac acquisition on February 1, 2008	--	186,558	--	186,558
Net proceeds from issuance of Limited Partner Units in connection with Distribution Reinvestment Plan	--	11,455	--	11,455
Net proceeds from issuance of Limited Partner Units in connection with Employee Unit Purchase Plan	--	758	--	758
Net proceeds from issuance of Limited Partner Units	--	263,643	--	263,643
Acquisition of treasury units	--	(9)	--	(9)
Net income allocation	32,583	160,969	--	193,552
Cash distributions	(54,926)	(273,071)	--	(327,997)
Non-cash contribution	--	797	--	797
Amortization of equity awards	--	1,333	--	1,333
Changes in fair values of crude oil financial instruments	--	--	(19,257)	(19,257)
Reclassification adjustment for loss included in net income related to crude oil financial instruments	--	--	37,898	37,898
Changes in fair values of treasury lock financial instruments	--	--	(26,802)	(26,802)
Reclassification adjustment for loss included in net income related to treasury lock financial instruments	--	--	4,923	4,923
Balance, December 31, 2008	$ (110,309)	$ 1,747,583	$ (45,795)	$ 1,591,479

See Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

NOTE 1. PARTNERSHIP ORGANIZATION

Partnership Organization

TEPPCO Partners, L.P. (the "Partnership") is a publicly traded, diversified energy logistics company with operations that span much of the continental United States. Our limited partner units ("Units") are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "TPP". We were formed in March 1990 as a Delaware limited partnership. 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.

We operate through TE Products Pipeline Company, LLC ("TE Products"), TCTM, L.P. ("TCTM") TEPPCO Midstream Companies, LLC ("TEPPCO Midstream"), and beginning February 1, 2008, through TEPPCO Marine Services, LLC ("TEPPCO Marine Services"). 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, 99.999% membership interests in each of TE Products and TEPPCO Midstream and a 100% membership interest in TEPPCO Marine Services. TEPPCO GP, Inc. ("TEPPCO GP"), our subsidiary, holds a 0.001% general partner interest in TCTM and a 0.001% managing member interest in each of TE Products and TEPPCO Midstream.

Dan L. Duncan and certain of his affiliates, including Enterprise GP Holdings L.P. ("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"). 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 GP Holdings L.P. ("DFIGP") and other entities controlled by Mr. Duncan own 17,073,315 of our Units, which include 2,500,000 of our Units owned by DFIGP. Under an amended and restated administrative services agreement ("ASA"), EPCO, Inc. ("EPCO"), a privately held company also controlled by Mr. Duncan, 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 amended and restated 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 contained 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 our operating companies, TCTM, TE Products and TEPPCO Midstream;
- 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. On November 6, 2008, our Partnership Agreement was amended to clarify that amendments of certain provisions thereof would not impair indemnitees' rights to receive expense advancements (in addition to indemnification) under the Partnership Agreement.

At December 31, 2008, 2007 and 2006, we had outstanding 104,704,861, 89,911,532 and 89,804,829 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.

Business Segments

We operate and report in four business segments:

- pipeline transportation, marketing and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment");
- gathering, pipeline transportation, marketing and storage of crude oil, distribution of lubrication oils and specialty chemicals and fuel transportation services ("Upstream Segment");
- gathering of natural gas, fractionation of natural gas liquids ("NGLs") and pipeline transportation of NGLs ("Midstream Segment"); and
- marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges ("Marine Services 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, natural gas, asphalt, heavy fuel oil and other heated oil products in this Report, collectively, as "petroleum products" or "products."

Allowance for Doubtful Accounts

Our allowance for doubtful accounts balance is generally determined based on specific identification and estimates of future uncollectible accounts, as appropriate. 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 estimates associated with the allowance for doubtful accounts to assess the sufficiency of the reserves to cover potential losses. The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Balance at January 1	$ 125	$ 100	$ 250
Charges to expense (1)	2,434	25	64
Deductions and other	--	--	(214)
Balance at December 31	$ 2,559	$ 125	$ 100

(1) Charges to expense for the year ended December 31, 2008 include the write-off of receivables primarily attributable to two customer bankruptcies.

Asset Retirement Obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. 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 8 for further information regarding our AROs.

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 principal 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 fractionation facilities in Colorado. The Marine Services Segment's principal assets consist of tow boats and tank barges used in the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products.

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 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.

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 sufficient 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. Our results for the year ended December 31, 2006 reflects 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 liquid investments 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 6.43%, 6.45% and 6.27% for the years ended December 31, 2008, 2007 and 2006, respectively.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling financial or equity interest, after the elimination of all significant intercompany accounts and transactions. We evaluate our financial interests in companies 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.

If an investee is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the 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. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates 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 investments in Seaway Crude Pipeline Company ("Seaway") and Centennial Pipeline LLC ("Centennial") are accounted for under the equity method of accounting, as we own 50% ownership interests in these entities and have 50% equal management with the other joint venture participants. Our investment in Texas Offshore Port System (a development stage enterprise) is accounted for under the equity method of accounting, as we own a 33% ownership interest in this entity and have equal voting rights with the other joint venture participants. Our investment in Jonah is accounted for under the equity method of accounting, as we have 50% equal management with the other participant, even though we own an approximate 80% economic interest in the partnership.

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

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management with input from legal counsel assesses such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management with input from 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.

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. None of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized.

At December 31, 2008 and 2007, our accrued liabilities for environmental remediation projects totaled $6.9 million and $4.0 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in actual cash required to remediate contamination for which we are responsible.

The following table presents the activity of our environmental reserve for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Balance at January 1	$ 4,002	$ 1,802	$ 2,447
Charges to expense	4,981	3,402	1,887
Deductions and other	(2,047)	(1,202)	(2,532)
Balance at December 31	$ 6,936	$ 4,002	$ 1,802

Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles ("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 financial instruments 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 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 financial instruments (including certain financial 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 financial instrument depends on the intended use of the financial instrument and the resulting designation, which is established at the inception of a financial instrument.

Our financial instruments consist primarily of contracts for the purchase and sale of petroleum products in connection with our crude oil marketing activities. Substantially all financial 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 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 financial instruments 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 financial instruments 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 financial instrument is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

For financial instruments designated as fair value hedges, changes in the fair value of a financial instrument 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 financial instrument and hedged asset or liability reflected on the balance sheet. Changes in the fair value of a financial instrument 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 financial instrument 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 financial instrument contract and the hedged item over time. The ineffective portion of the change in fair value of a financial 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 financial instrument is no longer effective in offsetting changes in the fair value or cash flows of the hedged item, or the financial instrument expires or is sold, terminated, or exercised, or the financial instrument 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 financial instrument as a hedging instrument is no longer appropriate.

When hedge accounting is discontinued because it is determined that the financial instrument no longer qualifies as an effective fair value hedge, we continue to carry the financial instrument 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 financial instrument 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 financial instrument 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 financial instrument 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.

Revised Texas Franchise Tax

In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its pre-existing franchise tax to include limited partnerships, limited liability companies, corporations and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas has changed from non-taxable to taxable. TE Products (formerly TE Products Pipeline Company, Limited Partnership) and TEPPCO Midstream (formerly TEPPCO Midstream Companies, L.P.) each converted into a Texas limited partnership and immediately thereafter each merged into a separate newly-formed Texas limited liability company on June 30, 2007. The pre-June 30, 2007 revenue of each of these former partnerships was not subject to the Revised Texas Franchise Tax because the former partnerships did not conduct business in Texas after June 30, 2007.

For the years ended December 31, 2008, 2007 and 2006, our provision for income taxes is applicable to our state tax obligations under the Revised Texas Franchise Tax. At December 31, 2008 and 2007, we had current tax liabilities of $3.9 million and $1.2 million, respectively. At December 31, 2008, we had a deferred tax liability of less than $0.1 million, while at December 31, 2007, we had a deferred tax asset of less than $0.1 million. During the years ended December 31, 2008 and 2007, we recorded increases in current income tax liabilities of $4.5 million and $1.2 million, respectively. During the years ended December 31, 2008 and 2007, we recorded a less than $0.1 million increase to deferred tax liability and a $0.7 million reduction to deferred tax liability, respectively. The offsetting net charges to deferred tax expense and income tax expense 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, customer contracts related to the acquisition of crude oil supply and transportation assets, customer relationships and non-compete agreements related to the acquisition of the marine assets and other intangible assets (see Note 11). Included in equity investments on the consolidated balance sheets are excess investments in Centennial, 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 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 purchase, sale and exchange agreements. Receivables and payables arising from exchange 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. Our Upstream Segment also acquires and disposes of crude oil under purchase, sale, buy/sell and exchange agreements. Additionally, our Upstream Segment acquires crude oil inventory through a pipeline loss allowance ("PLA") in certain of our pipeline tariffs, whereby the shipper conveys physical crude oil to us, in addition to a cash tariff payment for transportation services, in exchange for our bearing the risk of pipeline volumetric losses. These PLA barrels are recorded to inventory based on the current market value at the time the barrels are transported and later sold. 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 pipeline transportation, marketing and storage of refined products and LPGs, intrastate pipeline 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. Refined products terminaling revenues are recognized as products are out-loaded. From time to time, we buy and sell products to balance our inventory for operational needs, and the gains or losses 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 partner and establishing a margin by selling refined products for physical delivery through spot and contract sales. These marketing activities are conducted at our Aberdeen and Boligee truck racks to independent wholesalers and retailers of refined products. Spot purchases and sales are generally contracted to occur on the same day.

Our Upstream Segment revenues are earned from gathering, pipeline transporting, marketing and storing crude oil, distributing lubrication oils and specialty chemicals, and fuel transportation services principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Revenues are also generated from trade documentation and terminaling 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 terminaling services 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. In addition, when PLA barrels in crude oil inventory are sold, we recognize gains or losses in revenues depending on the current market price at the date of sale.

Our Midstream Segment revenues are earned from the gathering of natural gas, pipeline 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. Based upon contract terms, fractionation revenues are recognized based upon the volume of NGLs fractionated at a fixed rate per gallon. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of natural gas imbalances that are settled in-kind. Since we record natural gas imbalances using average market prices, the results of our Midstream Segment are affected by changes in the prices of natural gas.

Our Marine Services Segment revenues are earned from inland and offshore transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. We also provide offshore flow-back operations relating to well-testing and pipeline remediation and utilize our offshore tugs in general towing operations. Our transportation services are generally provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement. Most of the inland term contracts have one-year terms with the remainder having terms of up to two years. Substantially all of the inland contracts have renewal options, which are exercisable subject to agreement on rates applicable to the option terms. Most of the offshore service and transportation contracts have up to one-year terms with renewal options, which are exercisable subject to agreement on rates applicable to the option terms, or are spot contracts. A spot contract is an agreement with a customer to move cargo within designated operating areas for a rate negotiated at the time the cargo movement takes place. Revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which are generally less than ten days in duration. We estimate unbilled revenue at the end of each financial reporting period. Unbilled revenue represents revenue attributable to that portion of transportation services that has taken place prior to period end which is part of a voyage still in progress and has not yet been invoiced. We do not assume ownership of the products we transport in this segment. As is typical for inland and offshore affreightment contracts, the term contracts establish set 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. The costs of fuel, substantially all of which is a pass through expense, and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts.

Equity Awards

We account for equity awards in accordance with SFAS No. 123(R), *Share-Based Payment*. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying Units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity award is amortized to earnings on a straight-line basis over the requisite service or vesting period of the equity 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

The accounting standard setting bodies have recently issued the following accounting guidance that may affect our future financial statements: SFAS No. 141(R), *Business Combinations*; FASB Staff Position (“FSP”) SFAS 142-3, *Determination of the Useful Life of Intangible Assets*; SFAS No. 157, *Fair Value Measurements*; SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133*; Emerging Issues Task Force (“EITF”) 08-6, *Equity Method Investment Accounting Considerations*; and EITF 07-4, *Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships (“MLPs”)*.

SFAS No. 141(R), *Business Combinations*. SFAS 141(R) replaces SFAS No. 141, *Business Combinations* and was effective January 1, 2009. SFAS 141(R) retains the fundamental requirements of SFAS 141 in that the acquisition method of accounting (previously termed the “purchase method”) is used for all business combinations and for the “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. SFAS 141(R) will have an impact on the way in which we evaluate acquisitions.

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 resulting 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 net income 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.

FSP No. FAS 142-3, Determination of the Useful Life of Intangible Assets. In April 2008, the FASB issued FSP No. 142-3, which revised the factors that should be considered in developing renewal or extension assumptions used in determining the useful lives of recognized intangible assets under SFAS No. 142, *Goodwill and Other Intangible Assets*. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements.

SFAS No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009. See Note 6 for information regarding fair value-related disclosures required for 2008 in connection with SFAS 157.

SFAS 157 applies 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 are 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. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133. SFAS 161 revised the disclosure requirements for financial instruments and related hedging activities to provide users of financial statements with an enhanced understanding of (i) why and how an entity uses financial instruments, (ii) how an entity accounts for financial instruments and related hedged items under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, and its related interpretations and (iii) how financial instruments and related hedged items affect an entity’s financial position, financial performance and cash flows.

SFAS 161 requires qualitative disclosures about objectives and strategies for using financial instruments, quantitative disclosures about fair value amounts of and gains and losses on financial instruments and disclosures about credit risk-related contingent features in financial instrument agreements. SFAS 161 was effective January 1, 2009, and we will apply its requirements beginning with the first quarter of 2009.

EITF 08-6, Equity Method Investment Accounting Considerations. EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments under SFAS 141(R) and SFAS 160. EITF 08-6 generally requires that (i) transaction costs should be included in the initial carrying value of an equity method investment; (ii) an equity method investor shall not test separately an investee's underlying assets for impairment, rather such testing should be performed in accordance with Accounting Principles Board Opinion No. 18 (i.e., on the equity method investment itself); (iii) an equity method investor shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment (any gain or loss to the investor resulting from the investee's share issuance shall be recognized in earnings); and (iv) a gain or loss should not be recognized when changing the method of accounting for an investment from the equity method to the cost method. EITF 08-6 was effective January 1, 2009.

EITF 07-4, Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to MLPs. EITF 07-4 prescribes the manner in which an MLP should allocate and present earnings per unit using the two-class method set forth in SFAS No. 128, *Earnings per Share*. Under the two-class method, current period earnings are allocated to the general partner (including earnings attributable to any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement. EITF 07-4 was effective for us on January 1, 2009. Our adoption of EITF 07-4 did not have a material impact on our earnings per unit computations and disclosures.

NOTE 4. ACCOUNTING FOR EQUITY AWARDS

The following table summarizes compensation expense by plan for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Phantom Unit Plans: (1) (2)			
1994 Long-Term Incentive Plan ("1994 LTIP") (3)	$ --	$ --	$ 4
1999 Phantom Unit Retention Plan	(128)	865	885
2000 Long Term Incentive Plan	(265)	397	352
2005 Phantom Unit Plan	(144)	976	1,152
EPCO, Inc. 2006 TPP Long-Term Incentive Plan:			
Unit options	158	65	--
Restricted units (4)	1,019	338	--
Unit appreciation rights ("UARs") (1) (2)	2	67	--
Phantom units (1)	8	12	--
TEPPCO Unit L.P.	113	--	--
TEPPCO Unit II L.P.	35	--	--
Compensation expense allocated under ASA (5)	1,683	1,062	201
Total compensation expense	$ 2,481	$ 3,782	$ 2,594

(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.
(2) The decrease in compensation expense for the year ended December 31, 2008, is primarily due to a decrease in the Unit price at December 31, 2008, as compared to the Unit price at December 31, 2007.
(3) 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.
(4) As used in the context of the EPCO, Inc. 2006 TPP Long-Term Incentive Plan, 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 under other EPCO compensation plans allocated to us from EPCO under the ASA in connection with shared service employees working on our behalf (see Note 15).

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 18,600 phantom units and 31,600 phantom units were outstanding under the 1999 Plan at December 31, 2008 and 2007, respectively. In April 2008, 13,000 phantom units vested and $0.4 million was paid out to one participant in the second quarter of 2008. The remaining awards outstanding at December 31, 2008 cliff vest as follows: 13,000 in April 2009 and 5,600 in January 2010. At December 31, 2008 and 2007, we had accrued liability balances of $0.4 million and $1.0 million, respectively, for compensation related to the 1999 Plan. For the years ended December 31, 2008 and 2007, participants received $62 thousand and $95 thousand, respectively, in cash distributions.

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, 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 intangible assets and equity investments. The cost of capital is determined at the date each award is granted.

On December 31, 2007, 19,700 phantom units were outstanding, of which 8,400 phantom units vested on December 31, 2007, and $0.5 million was paid out to participants in the first quarter of 2008. At December 31, 2008, a total of 11,300 phantom units vested and will be paid out to participants in the first quarter of 2009. At December 31, 2008 and 2007, we had accrued liability balances of $0.2 million and $0.9 million, respectively, for compensation related to the 2000 LTIP. After payout in the first quarter of 2009 on awards which vested on December 31, 2008, there will be no remaining phantom units outstanding under the 2000 LTIP. For the years ended December 31, 2008 and 2007, participants received $38 thousand and $54 thousand, respectively, in cash distributions.

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, 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.

On December 31, 2007, 36,200 phantom units vested and $1.6 million was paid out to participants in the first quarter of 2008. At December 31, 2008, a total of 36,600 phantom units vested and will be paid out to participants in the first quarter of 2009. At December 31, 2008 and 2007, we had accrued liability balances of $0.6 million and $2.6 million, respectively, for compensation related to the 2005 Phantom Unit Plan. After the payout in the first quarter of 2009 on awards which vested on December 31, 2008, there will be no remaining phantom units outstanding under the 2005 Phantom Unit Plan. For the years ended December 31, 2008 and 2007, participants received $0.1 million and $0.2 million, respectively, in cash distributions.

2006 LTIP

The EPCO, Inc. 2006 TPP Long-Term Incentive Plan ("2006 LTIP") provides for awards of our Units and other rights to our non-employee directors and to certain 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. The 2006 LTIP is effective until the earlier of (i) December 8, 2016, (ii) the time by which all available Units under the 2006 LTIP have been delivered to participants, or (iii) the time of termination of the 2006 LTIP by EPCO or the ACG Committee. 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. After giving effect to outstanding unit options and restricted units at December 31, 2008, and the forfeiture of restricted units through December 31, 2008, a total of 4,487,084 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 (1) (2)	155,000	45.35	
Outstanding at December 31, 2007	155,000	45.35	
Granted (3)	200,000	35.86	
Outstanding at December 31, 2008	355,000	40.00	4.57
Options exercisable at:			
December 31, 2008	--	$ --	--

(1) During 2008, these unit option grants were amended. The expiration dates of these awards granted on May 22, 2007 were modified from May 22, 2017 to December 31, 2012.
(2) The total grant date fair value of these awards was $0.4 million based upon the following assumptions: (i) expected life of the 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) The total grant date fair value of these awards granted on May 19, 2008 was $0.3 million based upon the following assumptions: (i) expected life of the option of 4.7 years; (ii) risk-free interest rate of 3.3%; (iii) expected distribution yield on Units of 7.9%; (iv) estimated forfeiture rate of 17%; and (v) expected Unit price volatility on Units of 18.7%.

At December 31, 2008, total unrecognized compensation cost related to nonvested unit options granted under the 2006 LTIP was an estimated $0.6 million. We expect to recognize this cost over a weighted-average period of 2.95 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	
Granted (3)	96,900	$ 29.54
Vested	(1,000)	$ 40.61
Forfeited	(1,000)	$ 35.86
Restricted Units at December 31, 2008	157,300	

(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 $45.35 per Unit and an estimated forfeiture rate of 17%.

(3) Aggregate grant date fair value of restricted unit awards issued during 2008 was $2.8 million based on grant date market prices ranging from $34.63 to $35.86 per Unit and an estimated forfeiture rate of 17%.

The total fair value of our restricted unit awards that vested during the year ended December 31, 2008 was $24 thousand. At December 31, 2008, total unrecognized compensation cost related to restricted units was $3.7 million, and these costs are expected to be recognized over a weighted-average period of 2.8 years.

Phantom Units

At December 31, 2008 and 2007, a total of 1,647 phantom units were outstanding, which have been awarded under the 2006 LTIP to three of the non-executive members of the board of directors. 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. 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. Phantom unit awards to non-executive directors are accounted for in a manner similar to SFAS 123(R) liability awards.

UARs

At December 31, 2008 and 2007, a total of 431,377 UARs and 401,948 UARs, respectively, were outstanding, which have been awarded under the 2006 LTIP to non-executive members of the board of directors and to certain employees providing services directly to us.

Non-Executive Members of the Board of Directors. At December 31, 2008, a total of 95,654 UARs, awarded to non-executive members of the board of directors under the 2006 LTIP, were outstanding at a weighted average exercise price of $41.82 per Unit (66,225 UARs issued in 2007 at an exercise price of $45.30 per Unit to the then three non-executive members of the board of directors and 29,429 UARs issued in 2008 at an exercise price of $33.98 per Unit to a non-executive member of the board of directors in connection with his election to the board). The UARs are 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 in a manner similar to SFAS 123(R) liability awards.

Employees. At December 31, 2008 and 2007, a total of 335,723 UARs, awarded under the 2006 LTIP to certain employees providing services directly to us, were outstanding 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.

Employee Partnerships

EPCO formed TEPPCO Unit L.P. (“TEPPCO Unit”) and TEPPCO Unit II L.P. (“TEPPCO Unit II”) (collectively, “Employee Partnerships”) to serve as an incentive arrangement for key employees of EPCO by providing them with a “profits interest” in the Employee Partnerships. Certain EPCO employees who perform services for us, including our chief executive officer and other executive officers, were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of our Units. The Class B limited partner interests are subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting of the profits interest, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in the Employee Partnerships will also lapse upon certain change in control events.

The following is a discussion of the significant terms of TEPPCO Unit and TEPPCO Unit II.

TEPPCO Unit. On September 4, 2008, EPCO formed a Delaware limited partnership, TEPPCO Unit, for which it serves as the general partner, to serve as an incentive arrangement for certain employees of EPCO, including our executive officers. EPCO Holdings, Inc. ("EPCO Holdings"), an affiliate of EPCO, contributed approximately $7.0 million to TEPPCO Unit as a capital contribution with respect to its interest and was admitted as the Class A limited partner of TEPPCO Unit. TEPPCO Unit purchased 241,380 Units directly from us in an unregistered transaction at the public offering price concurrently with the closing of our September 2008 equity offering (see Note 13). Certain EPCO employees who perform services for us, including executive officers, were issued Class B limited partner interests and admitted as Class B limited partners of TEPPCO Unit without any capital contribution. The Class B limited partner interests, which entitle the holder to participate in the appreciation in value of our Units, are equity-based compensatory awards designed to incentivize officers and employees of EPCO who perform services for us to enhance the long-term value of our Units.

Compensation expense attributable to these awards is based on the estimated grant date fair value of each award. A portion of the fair value of these equity-based awards is allocated to us under the ASA as a non-cash expense. We are not responsible for reimbursing EPCO for any expenses of TEPPCO Unit, including the value of any contributions of cash or our Units made by private company affiliates of EPCO at the formation of TEPPCO Unit.

Unless otherwise agreed to by EPCO, EPCO Holdings and a majority in interest of the Class B limited partners or unless other specified dissolution events occur, TEPPCO Unit will terminate at the earlier of (i) thirty days following September 4, 2013 (five years from the date of TEPPCO Unit's agreement of limited partnership) or (ii) a change in control of EPCO, Enterprise GP Holdings, or us. Summarized below are certain material terms regarding distributions by TEPPCO Unit to its partners:

§ Distributions of Cash Flow – Each quarter, 100% of the cash distributions received by TEPPCO Unit from us in that quarter will be distributed to the Class A limited partner until the Class A limited partner has received an amount equal to the Class A preferred return (as defined below), and any excess distributions received by TEPPCO Unit in that quarter will be distributed to the Class B limited partners. The Class A preferred return equals the Class A capital base (as defined below) multiplied by a floating rate determined by EPCO, in its sole discretion, that will be no less than 4.5% and no greater than 5.725% per annum. The Class A limited partner's capital base equals the amount of any contributions of cash or cash equivalents made by the Class A limited partner to TEPPCO Unit, plus any unpaid Class A preferred return from prior periods, less any distributions of cash or Units previously made to the Class A limited partner by TEPPCO Unit.

§ Liquidating Distributions – Upon liquidation of TEPPCO Unit (after satisfaction of any debt or other obligations of TEPPCO Unit), Units having a fair market value equal to the Class A capital base will be distributed to EPCO Holdings, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining Units will be distributed to the Class B limited partners.

§ Sale Proceeds – If TEPPCO Unit sells any Units that it owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

The grant date fair value of the Class B limited partner interests in TEPPCO Unit was $2.1 million. This fair value was estimated using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards of five years, (ii) a risk-free interest rate of 2.87%, (iii) an expected distribution yield on our Units of 7.28%, and (iv) an expected Unit price volatility for our Units of 16.42%. At December 31, 2008, there was an estimated $1.7 million of unrecognized compensation cost related to TEPPCO Unit. We will recognize our share of these costs in accordance with the ASA over a weighted average period of 4.68 years.

TEPPCO Unit II. On November 13, 2008, EPCO formed a Delaware limited partnership, TEPPCO Unit II, for which it serves as the general partner, to serve as an incentive arrangement for Mr. Thompson, our chief executive officer and an employee of EPCO. On the same date, Duncan Family Interests, Inc. ("DFI"), an affiliate of EPCO, contributed to TEPPCO Unit II 123,185 Units (with a value of approximately $3.1 million, based on the closing price of our Units on the NYSE on November 12, 2008) and was admitted as the Class A limited partner of TEPPCO Unit II. Mr. Thompson was issued 100% of the Class B limited partner interests and admitted as Class B limited partner of TEPPCO Unit II without any capital contribution. The Class B limited partner interest, which entitles Mr. Thompson to participate in the appreciation in value of our Units, is an equity-based compensatory award designed to incentivize him to enhance the long-term value of our Units.

Compensation expense attributable to this award is based on the estimated grant date fair value of the award and the fair value is allocated to us under the ASA. We are responsible for reimbursing EPCO for the amount of distributions of cash or securities, if any, made by TEPPCO Unit II to Mr. Thompson.

Unless otherwise agreed to by EPCO, DFI and the Class B limited partner or unless other specified dissolution events occur, TEPPCO Unit II will terminate at the earlier of (i) thirty days following November 13, 2013 (five years from the date of TEPPCO Unit II's agreement of limited partnership) or (ii) a change in control of EPCO or us. Summarized below are certain material terms regarding distributions by TEPPCO Unit II to its partners:

§ Distributions of Cash Flow – Each quarter, 100% of the cash distributions received by TEPPCO Unit II from us in that quarter will be distributed to the Class A limited partner until the Class A limited partner has received an amount equal to the Class A preferred return (as defined below), and any remaining excess distributions received by TEPPCO Unit II in that quarter will be distributed to the Class B limited partner. The Class A preferred return equals the Class A capital base (as defined below) multiplied by a rate of 6.31% per annum. The Class A limited partner's capital base equals the amount of any contributions of cash or cash equivalents made by the Class A limited partner to TEPPCO Unit II, plus any unpaid Class A preferred return from prior periods, less any distributions of cash or Units previously made to the Class A limited partner by TEPPCO Unit II (as described below).

§ Liquidating Distributions – Upon liquidation of TEPPCO Unit II (after satisfaction of any debt or other obligations of TEPPCO Unit II), Units having a fair market value equal to the Class A capital base will be distributed to DFI, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining Units will be distributed to the Class B limited partner.

§ Sale Proceeds – If TEPPCO Unit II sells any Units that it owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partner in the same manner as liquidating distributions described above.

The grant date fair value of the Class B limited partner interest in TEPPCO Unit II was $1.4 million. This fair value was estimated using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards of five years, (ii) a risk-free interest rate of 2.37%, (iii) an expected distribution yield on our Units of 13.87%, and (iv) an expected Unit price volatility for our Units of 66.38%. At

December 31, 2008, there was an estimated $1.3 million of unrecognized compensation cost related to TEPPCO Unit II. We will recognize our share of these costs in accordance with the ASA over a weighted average period of 4.87 years.

NOTE 5. EMPLOYEE BENEFIT PLANS

Retirement Plan

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") was a non-contributory, trustee-administered pension plan. 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 this plan.

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 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.

In accordance with SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, 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, 2008, all benefit obligations to TEPPCO RCBP plan participants have been settled. During the first quarter of 2008, the remaining balance of the TEPPCO RCBP was transferred to an EPCO benefit plan.

The components of net pension benefits costs for the TEPPCO RCBP for the years ended December 31, 2007 and 2006 were as follows:

	For Year Ended December 31,	
	2007	2006
Interest cost on projected benefit obligation	$ 14	$ 891
Expected return on plan assets	103	(412)
Recognized net actuarial loss	38	135
SFAS 88 settlement charge	87	3,545
Net pension benefits costs	$ 242	$ 4,159

The weighted average assumptions used to determine net periodic benefit cost for the TEPPCO RCBP for the year ended December 31, 2007, were a discount rate of 4.73% and an expected long-term rate of return on plan assets of 2%.

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:

Change in benefit obligation		
Benefit obligation at January 1, 2007	$	477
Interest cost		14
Actuarial loss		60
Benefits paid		(534)
Impact of settlement		(17)
Benefit obligation at December 31, 2007	$	--
Change in plan assets		
Fair value of plan assets at January 1, 2007	$	1,311
Actual return on plan assets		(72)
Benefits paid		(534)
Impact of settlement		(46)
Fair value of plan assets at December 31, 2007	$	659
Funded status	$	659
Amount Recognized in the Balance Sheet:		
Noncurrent assets	$	659
Net pension asset at December 31, 2007	$	659
Amount Recognized in Other Comprehensive Income:		
Net actuarial loss	$	57
Amortization of net actuarial gain		(124)
Total recognized in other comprehensive income	$	(67)

Plan Assets

At December 31, 2007, all plan assets for the TEPPCO RCBP were invested in money market securities.

Other Plans

EPCO maintains defined contribution plans for the benefit of employees providing services to us, and we reimburse EPCO for the cost of maintaining these plans in accordance with the ASA (see Note 15 for additional information related to the costs and expenses allocated to us for employee benefits).

NOTE 6. FINANCIAL INSTRUMENTS

The following table presents the estimated fair values of our financial instruments at December 31, 2008 and 2007:

	December 31,			
	2008		2007	
Financial Instruments	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents (1)	$ 28	$ 28	$ 23	$ 23
Accounts receivable (1)	790,374	790,374	1,381,871	1,381,871
Commodity financial instruments (2) (3)	15,711	15,711	10,458	10,458
Interest rate swaps (3) (4)	--	--	254	254
Financial liabilities:				
Accounts payable and accrued liabilities (1)	792,469	792,469	1,413,447	1,413,447
Fixed-rate debt (principal amount) (5)	2,000,000	1,553,218	1,355,000	1,370,830
Variable-rate debt (6)	516,654	516,654	490,000	490,000
Commodity financial instruments (2) (3)	15,708	15,708	29,355	29,355
Treasury rate locks (3) (4)	--	--	25,296	25,296

(1) Cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities 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.
(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. From time to time we utilize interest rate swaps and similar arrangements to manage a portion of our interest rate exposure, 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. At December 31, 2008, there were no interest related financial instruments outstanding.

Fair Value Hedges – Interest Rate Swaps

In January 2006, we entered into interest rate swap agreements with a total notional value of $200.0 million to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. Under the swap agreements, we paid a fixed rate of interest ranging from 4.67% to 4.695% and received a floating rate based on the three-month U.S. Dollar LIBOR rate. At December 31, 2007, the fair value of these interest rate swaps was an asset of $0.3 million. These interest rate swaps expired in January 2008.

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 value of $210.0 million and was set to mature in January 2028 to match the principal and maturity of the TE Products Senior Notes. During the years ended December 31, 2007 and 2006, we recognized reductions in interest expense of $0.5 million and $1.9 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. In September 2007, we terminated this 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 $1.0 million recognized in interest expense in January 2008 at the time the 7.51% Senior Notes were redeemed (see Note 12).

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 value 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, 2008 and 2007, the unamortized balance of the deferred gains was $18.1 million and $23.2 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.

Cash Flow Hedges – Treasury Locks

At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to anticipated debt incurrence. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions was designated as a cash flow hedge under SFAS No. 133 as amended and interpreted.

In October 2006 and February 2007, we entered into treasury lock agreements, accounted for as cash flow hedges, which extended through June 2007 for a notional value 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 accumulated other comprehensive income. These gains are being amortized using the effective interest method as reductions to future interest expense over the term of the forecasted fixed rate interest payments, which is ten years. Over the next twelve months, we expect to reclassify $0.1 million of accumulated other comprehensive income that was generated by these treasury locks as a reduction to interest expense. 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, accounted for as cash flow hedges, which extended through January 31, 2008 for a notional value totaling $600.0 million. At December 31, 2007, the fair value of the treasury locks was a liability of $25.3 million. In January 2008, these treasury locks were extended through April 30, 2008. In March 2008, these treasury locks were settled concurrently with the issuance of senior notes (see Note 12). The settlement of the treasury locks resulted in losses of $52.1 million, and these losses were recorded in accumulated other comprehensive income. We recognized approximately $3.6 million of this loss in interest expense as a result of interest payments hedged under the treasury locks not occurring as forecasted. The remaining losses are being amortized using the effective interest method as increases to future interest expense over the terms of the forecasted interest payments, which range from five to ten years. Over the next twelve months, we expect to reclassify $5.8 million of accumulated other comprehensive loss that was generated by these treasury locks as an increase to interest expense. In the event of early extinguishment of these senior notes, any remaining unamortized losses would be recognized in the statement of consolidated income at the time of extinguishment.

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, 2008, we had no commodity financial instruments that were accounted for as cash flow hedges. At December 31, 2007, we had a limited number of commodity financial instruments that were accounted for as cash flow hedges. Gains and losses on financial instruments used in cash flow hedges 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. No ineffectiveness was recognized as of December 31, 2008. In addition, we had some commodity financial instruments that did not qualify for hedge accounting. These financial instruments had a minimal impact on our earnings. The fair values of the open positions at December 31, 2008 and 2007 was an asset of $3 thousand and a liability of $18.9 million, respectively.

Adoption of SFAS 157 – Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS No. 157 that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability. These assumptions include estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data, or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 established a three-tier hierarchy that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the SFAS 157 hierarchy are described as follows:

- § Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur in sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the NYSE or New York Mercantile Exchange). Level 1 primarily consists of financial assets and liabilities such as exchange-traded financial instruments, publicly-traded equity securities and U.S. government treasury securities.

- § Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors for stocks, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are validated by inputs other than quoted prices (e.g., interest rates and yield curves at commonly quoted intervals). Level 2 includes non-exchange-traded instruments such as over-the-counter forward contracts, options, and repurchase agreements.

- § Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities measured on a recurring basis at December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels. At December 31, 2008, we had no Level 1 financial assets and liabilities.

	Level 2	Level 3	Total
Financial assets:			
Commodity financial instruments	$ 15,488	$ 223	$ 15,711
Total	$ 15,488	$ 223	$ 15,711
Financial liabilities:			
Commodity financial instruments	$ 15,338	$ 370	$ 15,708
Total	$ 15,338	$ 370	$ 15,708
Net financial liabilities, Level 3		$ (147)	

The determination of fair values above associated with our commodity financial instrument portfolios are developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our net financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Net Commodity Financial Instruments
Balance, January 1, 2008	$ (394)
Total gains included in net income (1)	247
Balance, December 31, 2008	$ (147)

(1) Total commodity financial instrument gains, recognized in revenues and included in net income on our statements of consolidated income, was $0.2 million for the year ended December 31, 2008.

NOTE 7. INVENTORIES

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

	December 31, 2008	December 31, 2007
Crude oil (1)	$ 32,792	$ 44,542
Refined products and LPGs (2)	406	18,616
Lubrication oils and specialty chemicals	11,127	9,160
Materials and supplies	8,581	7,178
NGLs	--	803
Total	$ 52,906	$ 80,299

(1) At December 31, 2008 and 2007, $30.7 million and $16.5 million, respectively, of our crude oil inventory was subject to forward sales contracts. Decrease in crude oil inventory is primarily due to a decrease in the market price of crude oil from December 31, 2007 to December 31, 2008.

(2) Refined products and LPGs inventory is managed on a combined basis. Decrease in refined products and LPGs inventory is primarily due to sales of product inventory in 2008.

Due to fluctuating commodity prices, 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, 2008, 2007 and 2006, we recognized LCM adjustments of approximately $12.3 million, $0.8 million and $1.7 million, respectively.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

Major categories of property, plant and equipment at December 31, 2008 and 2007, were as follows:

	Estimated Useful Life In Years	December 31, 2008	2007
Plants and pipelines (1)	5-40(4)	$ 1,919,646	$ 1,810,195
Underground and other storage facilities (2)	5-40(5)	296,806	254,677
Transportation equipment (3)	5-10	11,303	7,780
Marine vessels	20-30	453,041	--
Land and right of way		143,823	117,628
Construction work in progress		294,075	185,579
Total property, plant and equipment		3,118,694	2,375,859
Less accumulated depreciation		678,784	582,225
Property, plant and equipment, net		$ 2,439,910	$ 1,793,634

(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, 2008, 2007 and 2006:

	For Year Ended December 31, 2008	2007	2006
Depreciation expense (1)	$ 96,252	$ 81,093	$ 78,888
Capitalized interest (2)	19,170	11,030	10,681

(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.

Asset Retirement Obligations

We have 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.

The following table presents information regarding our AROs:

ARO liability balance, December 31, 2006	$	1,228
Accretion expense		118
ARO liability balance, December 31, 2007		1,346
Accretion expense		128
ARO liability balance, December 31, 2008	$	1,474

Property, plant and equipment at December 31, 2008, 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 2009, $0.2 million for 2010, $0.2 million for 2011, $0.2 million for 2012 and $0.2 million for 2013.

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, 2008 and 2007:

	Ownership Percentage at December 31, 2008	December 31, 2008	December 31, 2007
Downstream Segment:			
Centennial	50.0%	$ 71,841	$ 78,962
Other	25.0%	332	362
Upstream Segment:			
Seaway	50.0%	190,129	188,650
Texas Offshore Port System	33.3%	35,915	--
Midstream Segment:			
Jonah	80.64%	957,706	879,021
Total		$ 1,255,923	$ 1,146,995

The following table summarizes equity earnings (losses) by business segment for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31, 2008	2007	2006
Equity earnings (losses):			
Downstream Segment (1)	$ (14,603)	$ (12,396)	$ (8,018)
Upstream Segment	11,693	2,602	11,905
Midstream Segment	90,004	83,060	35,052
Intersegment eliminations	(4,401)	(4,511)	(2,178)
Total equity earnings	$ 82,693	$ 68,755	$ 36,761

(1) On March 1, 2007, we sold our ownership interest in Mont Belvieu Storage Partners, L.P. (“MB Storage”) to Louis Dreyfus Energy Services L.P. (“Louis Dreyfus”) (see Note 10).

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the year ended December 31, 2008, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

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, 2008, we did not invest any funds in Centennial. 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 year ended December 31, 2006, TE Products contributed $2.5 million to Centennial. TE Products has received no cash distributions from Centennial since its formation.

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, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. Seaway also has a connection to our South Texas system that allows it 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. 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, 2008, 2007 and 2006, we received distributions from Seaway of $13.8 million, $12.4 million and $20.5 million, respectively. During the years ended December 31, 2008, 2007 and 2006, we did not invest any funds in Seaway. Our share of undistributed earnings of Seaway totaled approximately $1.4 million at December 31, 2008.

Texas Offshore Port System

In August 2008, we, together with Enterprise Products Partners and Oiltanking Holding Americas, Inc. ("Oiltanking") formed Texas Offshore Port System, a joint venture to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of total crude oil storage capacity, and (iii) an 85-mile pipeline system that will have the capacity to deliver up to 1.8 million barrels per day of crude oil, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express ("PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises, LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the acquisition of requisite permits.

We, Enterprise Products Partners and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. A subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and an affiliate of Enterprise Products Partners have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. At December 31, 2008, we have invested $36.0 million in the joint venture.

Jonah

Enterprise Products Partners, through its affiliate, Enterprise Gas Processing, LLC, is our joint venture partner in Jonah, the partnership through which we have owned our interest in the system serving the Jonah and Pinedale fields in the greater Green River Basin in southwestern Wyoming. 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. Enterprise Products Partners serves as operator. In June 2008, Jonah completed the Phase V expansion, which increased the combined system capacity of the Jonah and Pinedale fields from 1.5 billion cubic feet (“Bcf”) per day to 2.35 Bcf per day. The increased capacity from the expansion has reduced system operating pressures and increased production rates and ultimate reserve recoveries. Enterprise Products Partners managed 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, beginning in August 2007, our ownership interest in Jonah was approximately 80.64%, and Enterprise Products Partners’ ownership interest in Jonah was approximately 19.36%. Amounts exceeding an agreed upon base cost estimate of $415.2 million were shared 19.36% by Enterprise Products Partners and 80.64% by us. Our ownership interest in Jonah is currently anticipated to remain at 80.64%. Through December 31, 2008, we have reimbursed Enterprise Products Partners $306.5 million ($44.9 million in 2008, $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, 2008 and 2007, we had payables to Enterprise Products Partners for costs incurred of $1.0 million and $9.9 million, respectively.

In early 2008, Jonah began an expansion of the portion of its system serving the Pinedale field, which is expected to further increase the combined system capacity of the Jonah and Pinedale fields from 2.35 Bcf per day to approximately 2.55 Bcf per day. This project will include an additional 17,000 horsepower of compression at the Paradise and Bird Canyon stations in Sublette County, Wyoming and involve construction of approximately 52 miles of 30-inch and 24-inch diameter pipelines. This expansion is expected to be completed in phases, with final completion expected in early 2009. The total anticipated cost of this system expansion is expected to be approximately $125.0 million. Our share of the costs of the construction is expected to be 80.64%, and Enterprise Products Partners’ share is expected to be 19.36%. Enterprise Products Partners is managing this construction project.

During the years ended December 31, 2008, 2007 and 2006, we received distributions from Jonah of $132.2 million, $100.0 million and $0, respectively. The 2007 amount included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the years ended December 31, 2008, 2007 and 2006, we invested cash of $129.8 million, $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, 2008 and 2007 is presented below (on a 100% basis):

	For Year Ended December 31, 2008			2007			2006		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income (Loss)
Downstream Segment (1)	$ 39,109	$ 6,335	$ (4,428)	$ 56,816	$ 13,156	$ 2,365	$ 73,124	$ 10,374	$ (583)
Upstream Segment	93,878	45,783	45,969	67,337	21,266	21,589	87,284	34,206	34,608
Midstream Segment (2)	232,825	111,070	111,791	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 (see Note 10).
(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.

Summarized combined balance sheet information by reporting segment as of December 31, 2008 and 2007, is presented below:

	December 31, 2008 Current Assets	Noncurrent Assets	Current Liabilities	Long-term Debt	Noncurrent Liabilities	Equity
Downstream Segment	$ 12,870	$ 239,414	$ 20,673	$ 120,000	$ 358	$ 111,253
Upstream Segment (1)	52,423	338,616	11,155	--	22	379,862
Midstream Segment	53,810	1,163,257	28,224	--	378	1,188,465

	December 31, 2007 Current Assets	Noncurrent Assets	Current Liabilities	Long-term Debt	Noncurrent Liabilities	Equity
Downstream Segment	$ 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

(1) Includes our ownership interest in Texas Offshore Port System as of December 31, 2008.

NOTE 10. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

Acquisitions

Cenac

On February 1, 2008, we, through our subsidiary, TEPPCO Marine Services, entered the marine transportation business for refined products, crude oil and condensate. We acquired transportation assets and certain intangible assets that comprised the marine transportation business of Cenac Towing Co., Inc. (“Cenac Towing”), 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 the Cenac acquisition was $444.7 million, which consisted of $258.2 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. On February 1, 2008, we repaid the $63.2 million of assumed debt in full with borrowings under our term credit agreement (see Note 12).

The following table summarizes the components of total consideration paid or issued in this transaction.

Cash payment for Cenac acquisition	$	256,593
Fair value of our 4,854,899 Units		186,558
Other cash acquisition costs paid to third-parties		1,589
Total consideration	$	444,740

We financed the cash portion of the 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 Cenac acquisition 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, and 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 the Cenac acquisition are included in our consolidated financial statements beginning at the date of acquisition, in a newly created business segment, Marine Services Segment. Our fleet of acquired tow boats and tank barges will continue to be operated by employees of Cenac under a transitional operating agreement with TEPPCO Marine Services 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 approximately 4.9 million Units issued in the transaction in connection with proposed sales thereof by Cenac and specified related persons for 10 years. If we or any of our affiliates sell any of the assets acquired from Cenac Towing prior to June 30, 2018 and recognize certain "built-in gains" for federal income tax purposes that are allocable to Cenac Towing, we have indemnification obligations under the purchase agreement to pay Cenac Towing an amount generally intended to compensate for the incremental level of double taxation imposed on Cenac Towing as a result of the sale. The purchase agreement prohibits Cenac from competing with our marine services business for two years or from soliciting employees and service providers of TEPPCO Marine Services 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 fair values. Such fair values have been developed using recognized business valuation techniques.

The following table summarizes estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

Property, plant and equipment	$	360,146
Intangible assets		63,500
Other assets		2,726
Total assets acquired		426,372
Long-term debt		(63,157)
Total liabilities assumed		(63,157)
Total assets acquired less liabilities assumed		363,215
Total consideration given		444,740
Goodwill	$	81,525

The $63.5 million 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 Cenac acquisition 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 ranges from 2 to 20 years.

Of the $444.7 million in consideration we paid or issued to complete the Cenac acquisition, $81.5 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 these assets.

Since the closing date of the Cenac acquisition was February 1, 2008, our statements of consolidated income do not include any earnings from these assets prior to this date. The following table presents selected pro forma earnings information for the years ended December 31, 2008 and 2007 as if the Cenac acquisition had been completed on January 1, 2008 and 2007, respectively, instead of February 1, 2008. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Cenac acquisition actually occurred on January 1, 2007 or 2008.

	For the Year Ended December 31,			
		2008		2007
Pro forma earnings data:				
Revenues	$	13,544,440	$	9,762,597
Costs and expenses		13,288,363		9,502,334
Operating income		256,077		260,263
Net income		195,626		282,902
Basic and diluted earnings per Unit:				
Units outstanding, as reported		97,530		89,850
Units outstanding, pro forma		100,000		94,690
Basic and diluted earnings per Unit, as reported	$	1.65	$	2.60
Basic and diluted earnings per Unit, pro forma	$	1.63	$	2.50

Horizon

On February 29, 2008, we expanded our Marine Services Segment with the acquisition of marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately-held Houston-based company and an affiliate of Mr. Cenac for $80.8 million in cash. We acquired 7 tow boats, 17 tank barges, rights to two tow boats under construction and certain related commercial and other agreements (or the associated economic benefits). In April 2008, we paid $3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, we paid $3.8 million upon delivery of the second tow boat. The acquired vessels transport asphalt, heavy fuel oil and other heated oil products to storage facilities and refineries along the Mississippi, Illinois and Ohio Rivers, and the Intracoastal Waterway. We financed the acquisition with borrowings under our term credit agreement.

The results of operations for the Horizon acquisition are included in our consolidated financial statements beginning at the date of acquisition, in our Marine Services Segment. 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 fair values. Such fair values have been developed using recognized business valuation techniques. The following table summarizes estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

Property, plant and equipment	$	71,216
Intangible assets		6,500
Other assets		981
Total assets acquired		78,697
Total consideration given		87,584
Goodwill	$	8,887

The $6.5 million 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 Horizon acquisition 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 ranges from 2 to 9 years.

Of the $87.6 million in consideration we paid to complete the acquisition of the Horizon business, $8.9 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 these assets and further expanding our Marine Services Segment.

Lubrication and Other Fuel Oil Assets

On August 1, 2008, we purchased lubrication and other fuel oil assets, located in Wyoming, from Quality Petroleum, Inc. for approximately $6.8 million, which includes $1.3 million related to a non-compete agreement. The assets, included in our Upstream Segment, consist of operating inventory, buildings, land and various equipment and the assignment of certain distributor agreements. We funded the purchase through borrowings under our revolving credit facility, and we allocated the purchase price primarily to property, plant and equipment, goodwill, inventory and intangible assets. We recorded $0.7 million of goodwill related to this acquisition.

Cavern Assets

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

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 provides 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 are made according to the terms specified in the transition services agreement.

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.

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 petroleum products	$ 3,828
Other	932
Total operating revenues	4,760
Costs and expenses:	
Purchases of petroleum products	3,000
Operating expense	182
Depreciation and amortization	51
Taxes – other than income taxes	30
Total costs and expenses	3,263
Income from discontinued operations	$ 1,497

Net operating 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 operations:	
Net income	$ 19,369
Depreciation and amortization	51
Gain on sale of Pioneer plant	(17,872)
Increase in inventories	(27)
Net operating cash provided by discontinued operations	$ 1,521

NOTE 11. INTANGIBLE ASSETS AND GOODWILL

Intangible Assets

The following table summarizes our intangible assets, including excess investments, being amortized at December 31, 2008 and 2007:

	December 31, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Downstream Segment:				
Transportation agreements	$ 1,000	$ (408)	$ 1,000	$ (358)
Other	5,621	(764)	4,927	(325)
Subtotal	6,621	(1,172)	5,927	(683)
Upstream Segment:				
Transportation agreements	888	(395)	888	(335)
Other	10,580	(3,009)	10,005	(3,046)
Subtotal	11,468	(3,404)	10,893	(3,381)
Midstream Segment:				
Gathering agreements	239,649	(125,811)	239,649	(107,356)
Fractionation agreements	38,000	(20,425)	38,000	(18,525)
Other	306	(164)	306	(149)
Subtotal	277,955	(146,400)	277,955	(126,030)
Marine Services Segment:				
Customer relationship intangibles	51,320	(3,121)	--	--
Other	18,680	(4,294)	--	--
Subtotal	70,000	(7,415)	--	--
Total intangible assets	366,044	(158,391)	294,775	(130,094)
Excess investments: (1)				
Downstream Segment (2)	33,390	(26,128)	33,390	(21,861)
Upstream Segment (3)	26,908	(5,820)	26,908	(5,135)
Midstream Segment (4)	12,580	(241)	6,988	(95)
Subtotal	72,878	(32,189)	67,286	(27,091)
Total intangible assets, including excess investments	$ 438,922	$ (190,580)	$ 362,061	$ (157,185)

(1) Excess investments are included in “Equity Investments” in our consolidated balance sheets.
(2) Relates to our investment in Centennial.
(3) Relates to our investment in Seaway.
(4) Relates to our investment in Jonah.

The following table presents the amortization expense of our intangible assets and excess investments by segment for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Intangible assets:			
Downstream Segment	$ 489	$ 628	$ 59
Upstream Segment	698	652	716
Midstream Segment	20,370	22,734	28,044
Marine Services Segment	7,415	--	--
Subtotal	28,972	24,014	28,819
Excess investments: (1)			
Downstream Segment	4,267	5,282	3,632
Upstream Segment	685	685	686
Midstream Segment	146	95	--
Subtotal	5,098	6,062	4,318
Total amortization expense	$ 34,070	$ 30,076	$ 33,137

(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 values assigned to our customer relationships and non-compete agreements related to the acquisition of the marine assets are generally amortized on a straight-line basis from 2 to 20 years (see Note 10).

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 are amortizing 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 from excess investments allocated to equity earnings for the years ending December 31:

	Intangible Assets	Excess Investments
2009	$ 26,417	$ 5,771
2010	24,558	1,141
2011	22,672	1,141
2012	17,200	1,141
2013	15,543	1,141

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, 2008 and 2007, by business segment:

	December 31,	
	2008	2007
Downstream Segment	$ 1,339	$ 1,339
Upstream Segment	14,860	14,167
Marine Services Segment	90,412	--
Total goodwill	$ 106,611	$ 15,506

NOTE 12. DEBT OBLIGATIONS

The following table summarizes the principal amounts outstanding under all of our debt instruments at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
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: (3)		
Revolving Credit Facility, due December 2012	$ 516,654	$ 490,000
7.625% Senior Notes, due February 2012	500,000	500,000
6.125% Senior Notes, due February 2013	200,000	200,000
5.90% Senior Notes, due April 2013	250,000	--
6.65% Senior Notes, due April 2018	350,000	--
7.55% Senior Notes, due April 2038	400,000	--
Total principal amount of long-term senior debt obligations	2,216,654	1,190,000
7.000% Junior Subordinated Notes, due June 2067 (3)	300,000	300,000
Total principal amount of long-term debt obligations	2,516,654	1,490,000
Adjustment to carrying value associated with hedges of fair value and unamortized discounts (4)	12,865	21,083
Total long-term debt obligations	2,529,519	1,511,083
Total Debt Instruments (4)	$ 2,529,519	$ 1,865,059
Standby letters of credit outstanding (5)	$ --	$ 23,494

(1) In January 2008, TE Products retired all of its outstanding debt by repaying at maturity $180.0 million principal amount of its 6.45% TE Products Senior Notes due 2008 and redeeming the remaining $175.0 million principal amount of its 7.51% TE Products Senior Notes due 2028. The redemption price for the 7.51% TE Products Senior Notes due 2028 was 103.755% (or $181.6 million, which included a $6.6 million make-whole premium) of the principal amount plus accrued and unpaid interest to January 28, 2008, the date of redemption, of $0.5 million.

(2) Includes $1.0 million related to fair value hedges and $2 thousand in unamortized discount. In January 2008, with the redemption of the 7.51% TE Products Senior Notes, the remaining unamortized loss was recognized in the statement of consolidated income.

(3) TE Products, TCTM, TEPPCO Midstream and Val Verde (collectively, the "Subsidiary Guarantors") have issued full, unconditional, joint and several guarantees of our senior notes, junior subordinated notes and revolving credit facility.

(4) From time to time we enter 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, 2008 and 2007, amount includes $5.2 million and $2.1 million of unamortized discounts, respectively, and $18.1 million and $23.2 million related to fair value hedges, respectively.

(5) Letters of credit were issued in connection with crude oil purchased during 2007.

Revolving Credit Facility

We have in place an unsecured revolving credit facility ("Revolving Credit Facility"), which matures on December 12, 2012. The Revolving Credit Facility allows us to request unlimited one-year extensions of the maturity date, subject to lender approval and satisfaction of certain other conditions. In July 2008, commitments under our facility were increased from $700.0 million to $950.0 million. The aggregate outstanding principal amount of swing line loans or same day borrowings permitted under the Revolving Credit Facility is $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 ("S&P") and Moody's Investors Service, Inc. ("Moody's"). The Revolving Credit Facility contains a term-out option 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.

During September 2008, Lehman Brothers Bank, FSB ("Lehman"), which had a 4.05% participation in our Revolving Credit Facility, stopped funding its commitment following the bankruptcy filing of its parent. Assuming that future fundings are not received for the Lehman percentage commitment, aggregate available capacity would be reduced by approximately $28.9 million.

The Revolving Credit Facility contains financial covenants that require us to maintain a ratio of Consolidated Funded Debt to Pro Forma EBITDA (as defined and calculated in the facility) of less than 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 12), 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). At December 31, 2008, $516.7 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 1.4%, and our available borrowing capacity under the facility was approximately $404.4 million. At December 31, 2008, 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. 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. We funded the retirement of both series of senior notes with borrowings under our term credit agreement.

On February 20, 2002 and January 30, 2003, we issued $500.0 million principal amount of 7.625% Senior Notes due 2012 and $200.0 million principal amount of 6.125% Senior Notes due 2013, respectively. These 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.

On March 27, 2008, we issued (i) $250.0 million principal amount of 5.90% Senior Notes due 2013, (ii) $350.0 million principal amount of 6.65% Senior Notes due 2018, and (iii) $400.0 million principal amount of 7.55% Senior Notes due 2038. The senior notes were issued at discounts of $0.2 million, $1.3 million and $2.2 million, respectively, and are being accreted to their face value over the applicable terms 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 50 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, 2008, we were in compliance with the covenants of our 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”). 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). 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. 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. 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 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 50 basis points; and thereafter at a redemption price equal to 100% of their principal amount plus accrued and unpaid 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, 2008, 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, 2008 and 2007:

		Fair Value December 31,	
	Face Value	**2008**	**2007**
6.45% TE Products Senior Notes, due January 2008 (1)	$ 180,000	$ --	$ 179,982
7.625% Senior Notes, due February 2012	500,000	468,083	536,765
6.125% Senior Notes, due February 2013	200,000	174,201	202,027
7.51% TE Products Senior Notes, due January 2028 (1)	175,000	--	181,571
5.90% Senior Notes, due April 2013	250,000	214,506	--
6.65% Senior Notes, due April 2018	350,000	280,698	--
7.55% Senior Notes, due April 2038	400,000	295,190	--
7.000% Junior Subordinated Notes, due June 2067	300,000	120,540	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.

Term Credit Agreement

In December 2007, we put in place a senior unsecured term credit agreement (“Term Credit Agreement”), with a borrowing capacity of $1.0 billion and a maturity date of December 19, 2008. During the first quarter of 2008, we borrowed $1.0 billion under the Term Credit Agreement to finance the retirement of TE Products’ senior notes, the Cenac and Horizon acquisitions and for other partnership purposes. In March 2008, we repaid the outstanding balance of the Term Credit Agreement with proceeds from the issuance of senior notes and other cash on hand and terminated the agreement.

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, 2008 (on a 100% basis) and the corresponding scheduled maturities of such debt.

	Scheduled Maturities of Debt
2009	$ 9,900
2010	9,100
2011	9,000
2012	8,900
2013	8,600
After 2013	84,400
Total scheduled maturities of debt	$ 129,900

At December 31, 2008 and 2007, Centennial's debt obligations consisted of $129.9 million and $140.0 million, respectively, borrowed under a master shelf loan agreement. 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.

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 past-due amount under Centennial's master shelf loan agreement not paid by Centennial (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 reflected under GAAP in our financial statements 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. 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).

In September 2008, we filed a universal shelf registration statement with the U.S. Securities and Exchange Commission ("SEC") that allows us to issue an unlimited amount of debt and equity securities and removed from registration securities remaining under our previous universal shelf registration statement.

On September 9, 2008, we issued and sold in an underwritten public offering 9.2 million Units at a price to the public of $29.00 per Unit, including 1.2 million Units sold upon exercise of the underwriters' over-allotment option granted in connection with the offering. The proceeds from the offering, net of underwriting discount and offering expenses, totaled approximately $257.0 million. Concurrently with this offering, we sold 241,380 unregistered Units at the public offering price of $29.00 to TEPPCO Unit, an affiliate of EPCO in which certain EPCO employees who perform services for us, including our executive officers, were issued Class B limited partner interests to incentivize them to enhance the long-term value of our Units. The net proceeds from the offering and the unregistered issuance to TEPPCO Unit were used to reduce indebtedness under our Revolving Credit Facility. For additional information regarding TEPPCO Unit and the equity-based compensatory awards issued therein, please see Note 4.

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, 2008, 2007 and 2006.

	For Year Ended December 31,		
	2008	2007	2006
Limited Partner Units	$ 273,071	$ 246,152	$ 196,665
General Partner Ownership Interest	5,573	5,024	4,014
General Partner Incentive	49,353	43,274	77,887
Total Cash Distributions Paid	$ 327,997	$ 294,450	$ 278,566
Total Cash Distributions Paid Per Unit	$ 2.84	$ 2.74	$ 2.70

Our quarterly cash distributions for 2007 and 2008 are presented in the following table:

	Cash Distribution History		
	Distribution per Unit	Record Date	Payment Date
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	0.6950	Jan. 31, 2008	Feb. 7, 2008
2008			
1st Quarter	$ 0.7100	Apr. 30, 2008	May 7, 2008
2nd Quarter	0.7100	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	0.7250	Oct. 31, 2008	Nov. 6, 2008
4th Quarter (1)	0.7250	Jan. 30, 2009	Feb. 6, 2009

(1) The fourth quarter 2008 cash distribution totaled approximately $91.4 million.

EPCO, Inc. TPP Employee Unit Purchase Plan

The EPCO, Inc. TPP Employee Unit Purchase Plan (the "Unit Purchase Plan") provides for discounted purchases of our Units by employees of EPCO and its affiliates. A maximum of 1,000,000 Units may be delivered under the Unit Purchase Plan (subject to adjustment as provided in the plan). The Unit Purchase Plan is effective until the earlier of (i) December 8, 2016, (ii) the time that all available Units under the plan have been purchased on behalf of the participants or (iii) the time of termination of the plan by EPCO or the Chairman or Vice Chairman of EPCO. As of December 31, 2008, 27,604 Units have been issued to employees under this plan.

Distribution Reinvestment Plan

Our distribution reinvestment plan ("DRIP") provides for the issuance of up to 10,000,000 Units. Units purchased through the DRIP may be acquired at a discount rating from 0% to 5% (currently set at 5%), which will be set from time to time by us. As of December 31, 2008, 418,233 Units have been issued in connection with the DRIP.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding Units since December 31, 2005:

	Limited Partner Units	Restricted Units	Treasury Units	Total
Balance, December 31, 2005	69,963,554	--	--	69,963,554
Units issued in connection with underwritten public offering	5,750,000	--	--	5,750,000
Issuance of Units to General Partner	14,091,275	--	--	14,091,275
Balance, December 31, 2006	89,804,829	--	--	89,804,829
Issuance of restricted units under 2006 LTIP	--	62,900	--	62,900
Forfeiture of restricted units	--	(500)	--	(500)
Units issued in connection with Unit Purchase Plan	4,507	--	--	4,507
Units issued in connection with DRIP	39,796	--	--	39,796
Balance, December 31, 2007	89,849,132	62,400	--	89,911,532
Issuance of Units in connection with Cenac acquisition on February 1, 2008	4,854,899	--	--	4,854,899
Units issued in connection with DRIP	378,437	----	----	378,437
Units issued in connection with Unit Purchase Plan	23,097	--	--	23,097
Issuance of restricted units under 2006 LTIP	--	96,900	--	96,900
Forfeiture of restricted units	--	(1,000)	--	(1,000)
Conversion of restricted units to Units	1,000	(1,000)	--	--
Acquisition of treasury units	(384)	--	384	--
Cancellation of treasury units	--	--	(384)	(384)
Issuance of unregistered Units to TEPPCO Unit	241,380	--	--	241,380
Units issued in connection with underwritten public offering	9,200,000	--	--	9,200,000
Balance, December 31, 2008	104,547,561	157,300	--	104,704,861

During the year ended December 31, 2008, 1,000 restricted units awards vested and were converted into Units. Of this amount, 384 were sold back to us by an employee to cover related withholding tax requirements. The total cost of these treasury units were approximately $9 thousand, which was allocated to our limited partners. Immediately upon acquisition, we cancelled such treasury units.

General Partner's Interest

At December 31, 2008 and 2007, we had deficit balances of $110.3 million and $88.0 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, 2008, 2007 and 2006, our General Partner was allocated $32.6 million (representing 16.83%), $46.0 million (representing 16.47%) and $57.7 million (representing 28.57%), respectively, of our net income and received $54.9 million, $48.3 million and $81.9 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, 2008 and 2007. 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 years ended December 31, 2008 and 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 crude oil hedges had forward positions that expired during 2008. While the crude oil hedges were in effect, changes in their fair values, to the extent the hedges were effective, are recognized in accumulated other comprehensive income until they are recognized in net income in future periods upon the contract expiration. The amounts related to settlements of treasury lock agreements are being amortized into earnings over the terms of the respective debt (see Note 6). Our accumulated other comprehensive loss balance consisted of a $23.9 million loss related to interest rate and treasury lock financial instruments and a $18.6 million loss associated with crude oil financial instruments at December 31, 2007. Our accumulated other comprehensive loss balance consisted of a $45.8 million loss related to interest rate and treasury lock financial instruments at December 31, 2008.

NOTE 14. BUSINESS SEGMENTS

We have four reporting segments:

- Our Downstream Segment, which is engaged in the pipeline transportation, marketing and storage of refined products, LPGs and petrochemicals;
- Our Upstream Segment, which is engaged in the gathering, pipeline transportation, marketing and storage of crude oil, distribution of lubrication oils and specialty chemicals and fuel transportation services;
- Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and pipeline transportation of NGLs; and
- Our Marine Services Segment, which is engaged in the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges.

The amounts indicated below as “Partnership and Other” for income and expense items (including operating income) relate primarily to intersegment eliminations from activities among our reporting segments. Amounts indicated below as “Partnership and Other” for assets and capital expenditures include the elimination of intersegment related party receivables and investment balances among our reporting segments and assets that we hold that have not been allocated to any of our reporting segments (including such items as corporate furniture and fixtures, vehicles, computer hardware and software, prepaid insurance and unamortized debt issuance costs on debt issued at the Partnership level).

Our Downstream Segment revenues are earned from pipeline transportation, marketing and storage of refined products and LPGs, intrastate pipeline 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 gasoline during the spring and summer driving seasons, although recent high gasoline prices have moderated this trend somewhat. 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 investment in Centennial (see Note 9).

Our Upstream Segment revenues are earned from gathering, pipeline 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 crude oil purchased at the lease along our pipeline systems, and 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 terminaling services, primarily at Cushing, Oklahoma, and Midland, Texas. Our Upstream Segment also includes our equity investments in Seaway and Texas Offshore Port System (see Note 9). The Seaway system 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. Seaway also has a connection to our South Texas system that allows it to receive both onshore and offshore domestic crude oil in the Texas Gulf Coast area for delivery to Cushing. Texas Offshore Port System, a joint venture between us and affiliates of Enterprise Products Partners and Oiltanking, was formed to design, construct, operate and own a new Texas offshore crude oil port and pipeline system.

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 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, a joint venture between an affiliate of Enterprise Products Partners and us, 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 an 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 year ended December 31, 2006.

Our Marine Services Segment revenues are earned from the marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. We entered the marine transportation business in February 2008 with the acquisition of assets and certain intangible assets from Cenac and Horizon on February 1, 2008 and February 29, 2008, respectively (see Note 10). These businesses service refineries and storage terminals along the Mississippi, Illinois and Ohio rivers, the Intracoastal Waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast and in the Gulf of Mexico.

The following table presents our measurement of earnings before interest expense for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Total operating revenues	$ 13,532,889	$ 9,658,060	$ 9,607,485
Less: Total costs and expenses	13,279,469	9,408,505	9,377,706
Operating income	253,420	249,555	229,779
Add: Gain on sale of ownership interest in MB Storage	--	59,628	--
Equity earnings	82,693	68,755	36,761
Interest income	1,091	1,676	2,077
Other income	953	1,346	888
Earnings before interest expense, provision for income taxes and discontinued operations	$ 338,157	$ 380,960	$ 269,505

A reconciliation of our earnings before interest expense, provision for income taxes and discontinued operations to net income for the years ended December 31, 2008, 2007 and 2006 is as follows:

	For Year Ended December 31,		
	2008	2007	2006
Earnings before interest expense, provision for income taxes and discontinued operations	$ 338,157	$ 380,960	$ 269,505
Interest expense – net	(139,988)	(101,223)	(86,171)
Income before provision for income taxes	198,169	279,737	183,334
Provision for income taxes	4,617	557	652
Income from continuing operations	193,552	279,180	182,682
Discontinued operations	--	--	19,369
Net income	$ 193,552	$ 279,180	$ 202,051

The table below includes information by segment, together with reconciliations to our consolidated totals for the periods indicated:

	Downstream Segment	Upstream Segment	Midstream Segment	Marine Services Segment	Partnership and Other	Consolidated
Revenues from third parties:						
Year ended December 31, 2008	$ 350,896	$ 12,872,544	$ 108,531	$ 164,274	$ --	$ 13,496,245
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
Revenues from related parties:						
Year ended December 31, 2008	$ 22,068	$ 882	$ 13,886	$ --	$ (192)	$ 36,644
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
Intersegment and intrasegment revenues:						
Year ended December 31, 2008	$ --	$ --	$ --	$ --	$ --	$ --
Year ended December 31, 2007	--	80	--	--	(80)	--
Year ended December 31, 2006	--	748	6,646	--	(7,394)	--
Total revenues:						
Year ended December 31, 2008	$ 372,964	$ 12,873,426	$ 122,417	$ 164,274	$ (192)	$ 13,532,889
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
Depreciation and amortization:						
Year ended December 31, 2008	$ 43,063	$ 20,928	$ 39,323	$ 23,015	$ --	$ 126,329
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
Operating income:						
Year ended December 31, 2008	$ 91,270	$ 95,683	$ 27,559	$ 34,507	$ 4,401	$ 253,420
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
Equity earnings (losses):						
Year ended December 31, 2008	$ (14,603)	$ 11,693	$ 90,004	$ --	$ (4,401)	$ 82,693
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

	Downstream Segment	Upstream Segment	Midstream Segment	Marine Services Segment	Partnership and Other	Consolidated
Earnings before interest expense, provision for income taxes and discontinued operations:						
Year ended December 31, 2008	$ 77,526	$ 108,164	$ 117,947	$ 34,520	$ --	$ 338,157
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
Capital expenditures:						
At December 31, 2008	$ 209,753	$ 33,429	$ 5,215	$ 43,557	$ 8,549	$ 300,503
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
Segment assets:						
At December 31, 2008	$ 1,320,870	$ 1,586,345	$ 1,529,125	$ 653,262	$ (39,782)	$ 5,049,820
At December 31, 2007	1,221,316	2,084,830	1,512,621	--	(68,710)	4,750,057
Investments in unconsolidated affiliates:						
At December 31, 2008	$ 63,222	$ 226,044	$ 957,706	$ --	$ 8,951	$ 1,255,923
At December 31, 2007	79,324	188,650	879,021	--	--	1,146,995
Intangible assets:						
At December 31, 2008	$ 5,449	$ 8,064	$ 131,555	$ 62,585	$ --	$ 207,653
At December 31, 2007	5,244	7,512	151,925	--	--	164,681
Goodwill:						
At December 31, 2008	$ 1,339	$ 14,860	$ --	$ 90,412	$ --	$ 106,611
At December 31, 2007	1,339	14,167	--	--	--	15,506

NOTE 15. RELATED PARTY TRANSACTIONS

The following table summarizes related party transactions for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Revenues from EPCO and affiliates:			
Sales of petroleum products (1)	$ 715	$ 320	$ 3,165
Transportation – NGLs (2)	13,785	13,153	10,225
Transportation – LPGs (3)	8,735	5,191	3,648
Other operating revenues (4)	13,318	1,761	1,517
Revenues from unconsolidated affiliates:			
Other operating revenues (5)	91	351	295
Related party revenues	$ 36,644	$ 20,776	$ 18,850
Costs and Expenses from EPCO and affiliates:			
Purchases of petroleum products (6)	$ 132,624	$ 61,596	$ 52,982
Operating expense (7)	104,878	96,947	103,924
General and administrative (8)	31,601	25,500	21,709
Costs and Expenses from unconsolidated affiliates:			
Purchases of petroleum products (9)	7,143	5,493	2,987
Operating expense (10)	7,926	8,736	5,094
Costs and Expenses from Cenac and affiliates:			
Operating expense (11)	45,382	--	--
General and administrative (12)	2,912	--	--
Related party costs and expenses	$ 332,466	$ 198,272	$ 186,696

(1) Includes sales from Lubrication Services, LLC (“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 from Enterprise Products Partners and certain of its subsidiaries.
(4) Includes sales of product inventory from TE Products to Enterprise Products Partners and other operating revenues on the TE Products pipeline and the Val Verde system from Enterprise Products Partners and certain of its subsidiaries.
(5) Includes sales of petroleum products, management fees and rental revenues from Centennial, Jonah and Seaway.
(6) Includes TCO purchases of petroleum products of $113.9 million, $45.1 million and $41.6 million from Enterprise Products Partners and certain of its subsidiaries for the years ended December 31, 2008, 2007 and 2006, respectively, and expenses related to TCO’s and LSI’s use of an affiliate of EPCO as a transporter.
(7) 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, 2008, 2007 and 2006, of $10.4 million, $13.6 million and $15.8 million, respectively, related to premiums paid by EPCO on our behalf. The majority of our insurance coverage, including property, liability, business interruption, auto and directors’ and officers’ liability insurance, is obtained through EPCO.
(8) 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.
(9) Includes TCO purchases of petroleum products from Jonah and Seaway and pipeline transportation expense from Seaway.
(10) Includes rental expense and other operating expense.
(11) Includes reimbursement for operating payroll, payroll related expenses, certain repairs and maintenance expenses and insurance premiums on our equipment under the transitional operating agreement with Cenac, pursuant to which, our fleet of acquired tow boats and tank barges (including those acquired from Horizon) are operated by employees of Cenac for a period of up to two years following the acquisition.

(12) Includes reimbursement for administrative payroll and payroll related expenses, as well as payment of a $42 thousand monthly service fee and a 5% overhead fee charged on direct costs incurred by Cenac to operate the marine assets in accordance with the transitional operating agreement.

The following table summarizes related party balances at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
Accounts receivable, related parties (1)	$ 15,758	$ 6,525
Accounts payable, related parties (2)	17,219	38,980

(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 and $3.4 million related to operational related charges from Cenac.

As an affiliate of EPCO and other companies controlled by Mr. Duncan, our transactions and agreements with them are not necessarily 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.

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;
- § Enterprise Gas Processing LLC, which is controlled by affiliates of EPCO and is our joint venture partner in Jonah;
- § Enterprise Offshore Port System, LLC, which is controlled by affiliates of EPCO and is one of our joint venture partners in Texas Offshore Port System; and
- § the Employee Partnerships, which are controlled by EPCO (see Note 4).

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 to our General Partner of $54.9 million, $48.3 million and $81.9 million during the years ended December 31, 2008, 2007 and 2006, respectively.

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.

EPCO Administrative Services Agreement

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, Enterprise Products Partners, Duncan Energy Partners, Enterprise GP Holdings and our respective general partners are parties to the ASA. The ACG Committees of each general partner have approved the ASA.

Under the ASA, we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits) (see Note 1). Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

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, 2008, 2007 and 2006 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, 2008, 2007 and 2006 include amounts we reimburse to EPCO for administrative services, including compensation of employees. We are responsible to reimburse EPCO for the amount of distributions of cash or securities, if any, made by TEPPCO Unit II to Mr. Thompson. 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 subsidiaries, and we and our subsidiaries 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 January 30, 2009, we entered into the Fifth Amended and Restated ASA, which amended the previous ASA to provide for the cash reimbursement to EPCO by us of distributions of cash or securities, if any, made by TEPPCO Unit II to its Class B limited partner, Mr. Thompson, our chief executive officer and an employee of EPCO (see Note 4). The Fifth Amended and Restated ASA also extends the term of EPCO's service obligations from December 2010 to December 2013.

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

Enterprise Products Partners (through an affiliate) is our joint venture partner in Jonah, the partnership through which we have owned our interest in the system serving the Jonah and Pinedale fields. Through December 31, 2008, we have reimbursed Enterprise Products Partners $306.5 million ($44.9 million in 2008, $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, 2008 and 2007, we had payables to Enterprise Products Partners for costs incurred of $1.0 million and $9.9 million, respectively (see Note 9). At December 31, 2008 and 2007, we had receivables from Jonah of $4.7 million and $6.0 million, respectively, for operating expenses. During the years ended December 31, 2008, 2007 and 2006, we received distributions from Jonah of $132.2 million, $100.0 million and $0, respectively. The 2007 amount included $11.6 million of distributions declared in 2006 and paid during the first quarter of 2007. During the years ended December 31, 2008, 2007 and 2006, Jonah paid distributions of $31.7 million, $9.5 million and $0, respectively, to the affiliate of Enterprise Products Partners that is our joint venture partner.

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-Pinedale 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-Pinedale 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.

Texas Offshore Port System Joint Venture

Enterprise Products Partners (through an affiliate) is one of our joint venture partners in Texas Offshore Port System which was formed in August 2008 to design, construct, operate and own a new Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. We, Enterprise Products Partners and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. A subsidiary of Enterprise Products Partners acts as construction manager and will act as operator. We and an affiliate of Enterprise Products Partners have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. Through December 31, 2008, we have invested $36.0 million in Texas Offshore Port System (see Note 9).

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 17,073,315 of our Units.

Concurrently with the acquisition of our General Partner, Enterprise GP Holdings acquired non-controlling ownership interests, accounted for as equity method investments, in Energy Transfer Equity, L.P. (“Energy Transfer Equity”) and LE GP, LLC, the general partner of 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.

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 was continued on a month-to-month basis through March 2008.

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. 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.

In December 2008, we entered into a lease agreement with Seminole Pipeline Company ("Seminole") and Mid-America Pipeline Company, LLC, ("MAPL") for the use of excess capacity on the Seminole pipeline system, a pipeline extending from Hobbs, New Mexico to Mont Belvieu, Texas. For Chaparral to use the excess capacity on Seminole, it must also access a segment of the MAPL pipeline as well. The primary term of this lease expired on January 31, 2009, and will continue on a month-to-month basis. Seminole and MAPL are subsidiaries of Enterprise Products Partners.

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.

See "Jonah Joint Venture" and "Texas Offshore Port System Joint Venture" within this Note 15 for descriptions of ongoing transactions involving our Jonah and Texas Offshore Port System joint ventures with Enterprise Products Partners.

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. Our 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 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 and 2008, we granted 155,000 and 200,000 unit options, respectively, to employees providing services to us (see Note 4).

The following table shows the computation of basic and diluted earnings per Unit for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Income from continuing operations	$ 193,552	$ 279,180	$ 182,682
Discontinued operations	--	--	19,369
Net income	193,552	279,180	202,051
General Partner's interest in net income	16.83%	16.47%	28.57%
Earnings allocated to General Partner:			
Income from continuing operations	$ 32,583	$ 45,987	$ 52,199
Discontinued operations	--	--	5,534
Net income allocated	32,583	45,987	57,733
BASIC EARNINGS PER UNIT:			
Numerator:			
Income from continuing operations	$ 160,969	$ 233,193	$ 130,483
Discontinued operations	--	--	13,835
Limited partners' interest in net income	$ 160,969	$ 233,193	$ 144,318
Denominator:			
Units	97,408	89,812	73,657
Time-vested restricted units	122	38	--
Total Weighted average Units outstanding	97,530	89,850	73,657
Basic earnings per Unit:			
Income from continuing operations	$ 1.65	$ 2.60	$ 1.77
Discontinued operations	--	--	0.19
Limited partners' interest in net income	$ 1.65	$ 2.60	$ 1.96
DILUTED EARNINGS PER UNIT:			
Numerator:			
Income from continuing operations	$ 160,969	$ 233,193	$ 130,483
Discontinued operations	--	--	13,835
Limited partners' interest in net income	$ 160,969	$ 233,193	$ 144,318
Denominator:			
Units	97,408	89,812	73,657
Time-vested restricted units	122	38	--
Total Weighted average Units outstanding	97,530	89,850	73,657
Diluted earnings per Unit:			
Income from continuing operations	$ 1.65	$ 2.60	$ 1.77
Discontinued operations	--	--	0.19
Limited partners' interest in net income	$ 1.65	$ 2.60	$ 1.96

Our General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our Partnership Agreement. At December 31, 2008, 2007 and 2006, we had outstanding 104,704,861, 89,911,532 and 89,804,829 Units, respectively.

NOTE 17. COMMITMENTS AND CONTINGENCIES

Litigation

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 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 at the time, 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. Pre-trial discovery in this proceeding is underway. 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.

In October 2005, 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 failed to conform to quality specifications of the Interconnect and Operator Balancing Agreement ("Interconnect Agreement") which has allegedly caused damages to the Opal Plant in excess of $28.0 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 system to the Opal Plant, in violation of the Interconnect Agreement. Jonah denies any liability to Williams. Discovery is ongoing.

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 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, 2008 and 2007, we had accrued liabilities of $6.9 million and $4.0 million, respectively, related to sites requiring environmental remediation activities.

In 1999, our Arcadia, Louisiana, facility and adjacent terminals were directed by the Remediation Services Division of the Louisiana Department of Environmental Quality (“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, 2008, we have an accrued liability of $0.5 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.

TEPPCO PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

We received a notice of probable violation from the U.S. Department of Transportation 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 and gas gathering 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. 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 or revenues.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2008. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
	Total	2009	2010	2011	2012	2013	Thereafter
Maturities of long-term debt (1)	$ 2,516,654	$ --	$ --	$ --	$ 1,016,654	$ 450,000	$ 1,050,000
Interest payments (2)	$ 2,624,102	$ 146,838	$ 146,838	$ 146,839	$ 127,474	$ 87,975	$ 1,968,138
Operating leases (3)	$ 55,696	$ 12,467	$ 10,640	$ 9,712	$ 9,045	$ 6,156	$ 7,676
Purchase obligations (4):							
Product purchase commitments:							
Estimated payment obligation:							
Crude oil	$ 212,435	$ 212,435	$ --	$ --	$ --	$ --	$ --
Refined Products	$ 10,594	$ 10,594	$ --	$ --	$ --	$ --	$ --
Other	$ 3,057	$ 1,772	$ 884	$ 401	$ --	$ --	$ --
Underlying major volume commitments:							
Crude oil (in barrels)	$ 4,409	$ 4,409	$ --	$ --	$ --	$ --	$ --
Refined Products (in barrels)	$ 353	$ 353	$ --	$ --	$ --	$ --	$ --
Service payment commitments (5)	$ 5,024	$ 4,675	$ 349	$ --	$ --	$ --	$ --
Contributions to Jonah (6)	$ 27,000	$ 27,000	$ --	$ --	$ --	$ --	$ --
Contributions to Texas Offshore Port System (7)	$ 70,000	$ 70,000	$ --	$ --	$ --	$ --	$ --
Capital expenditure obligations (8)	$ 116,733	$ 116,733	$ --	$ --	$ --	$ --	$ --
Other liabilities and deferred credits (9)	$ 28,826	$ --	$ 5,616	$ 5,607	$ 5,607	$ 2,096	$ 9,900

(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) 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 and the junior subordinated notes is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(3) We lease certain 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, 2008, 2007 and 2006, was $20.0 million, $22.1 million and $25.3 million, respectively.

(4) 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, 2008. 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.

(5) Includes approximately $4.5 million related to a shipment commitment on Centennial, approximately $0.4 million related to a commitment to pay for compression services on Val Verde and approximately $0.1 million related to the monthly service fee we pay Cenac to operate the marine assets in accordance with the transitional operating agreement.

(6) Expected contributions to Jonah in 2009 for our share of capital expenditures.

(7) Expected contributions to Texas Offshore Port System for our share of costs related to the TOPS and PACE projects. We are obligated under the joint venture agreement to contribute one-third of the funds to complete the projects, which we currently estimate will total $600.0 million for our share.
(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) Includes approximately $9.6 million of long-term deferred revenue payments, primarily in the Downstream and Upstream segments, which are being recognized into income as the services are performed and approximately $12.0 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

Guarantees

At December 31, 2008 and 2007, Centennial's debt obligations consisted of $129.9 million and $140.0 million, respectfully, borrowed under a master shelf loan agreement. In January 2008, we entered into an Amended Guaranty agreement with Centennial's lenders, under which the TEPPCO Guarantors are required, on a joint and several basis, to pay 50% of any past-due amount under Centennial's master shelf loan agreement not paid by Centennial. The Amended Guaranty also has a credit maintenance requirement whereby we may be required to provide additional credit support in the form of a letter of credit or pay certain fees if either of our credit ratings from S&P and Moody's falls below investment grade levels as specified in the Amended Guaranty. If Centennial defaults on its debt obligations, the estimated maximum potential amount of future payments for the TEPPCO Guarantors and Marathon is $65.0 million each at December 31, 2008. At December 31, 2008, we have a liability of $9.0 million, which is based upon the expected present value of amounts 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, 2008, TE Products has a liability of $3.9 million, which is based upon the expected present value of amounts 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 pieces of equipment. We currently estimate that our minimum lease payment related to this equipment will be $3.9 million for 2009. 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.

Motiva Project

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 or July 1, 2010, which ever comes first. 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. 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 one of the primary origination facilities 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 $355.0 million, which includes $25.0 million for the 11-mile, 20-inch pipeline, $24.0 million of capitalized interest and $17.0 million of mutually agreed upon scope changes requested by Motiva. Through December 31, 2008, we have spent approximately $170.1 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.

Texas Offshore Port System

We, through a subsidiary, own a one-third interest in the Texas Offshore Port System joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such expenditures currently expected to occur in 2010 and 2011. We have guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital expenditure obligations of our subsidiary in the joint venture. See Note 9 for further information.

Other

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2008, TCTM and TE Products had approximately 5.2 million barrels and 11.3 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 to cover product losses through circumstances beyond our control at levels we believe are consistent with the associated exposures.

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, 2008, 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, (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 and (5) hulls and certain liabilities which may arise from marine vessel operations. 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 coverage 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 plans

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, 2008, there were 355,000 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, 2008 was $40.00 per Unit. At December 31, 2008, none of these unit options were exercisable. As these options are exercised, we will reimburse EPCO for the gross unit option value of the options exercised to make EPCO whole for related employee tax withholding requirements. See Note 4 for additional information regarding our accounting for equity 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 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, 2008, 2007 and 2006, Valero Energy Corp. accounted for 21%, 16% and 14%, respectively, of our total consolidated revenues, and for the years ended December 31, 2008, 2007 and 2006, BP Oil Supply Company accounted for 16%, 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, 2008, 2007 and 2006.

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 and financing activities and (iii) cash payments for interest for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Decrease (increase) in:			
Accounts receivable, trade	$ 591,498	$ (529,055)	$ (67,317)
Accounts receivable, related parties	(8,884)	(5,986)	1,736
Inventories	28,526	(8,255)	(45,002)
Other current assets	4,669	(7,356)	25,850
Other	(13,763)	(17,527)	(10,740)
Increase (decrease) in:			
Accounts payable and accrued liabilities	(627,198)	558,111	44,348
Accounts payable, related parties	(12,877)	3,374	15,696
Other	(10,079)	(1,946)	(1,268)
Net effect of changes in operating accounts	$ (48,108)	$ (8,640)	$ (36,697)
Non-cash investing activities:			
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 (see Note 9)	$ 995	$ 9,878	$ 8,732
Liabilities for Construction work in progress	$ 17,213	$ 11,334	$ 10,786
Non-cash financing activities:			
Issuance of Units in Cenac acquisition (see Note 10)	$ 186,558	$ --	$ --
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 128,136	$ 104,220	$ 88,107
Cash payments for state income taxes	$ 1,947	$ 20	$ --

We determine net cash flows provided by operating activities using the indirect method, which adjusts net income for items that did not affect cash. Under GAAP, we use the accrual basis of accounting to determine net income. This basis requires that we record revenue when earned and expenses when incurred. Earned revenues may include credit sales that have not been collected in cash and expenses incurred that may not have been paid in cash. The extent to which changes in operating accounts influence net cash flows provided by operating activities generally depends on the following:

§ The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period.

§ If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges.

§ Additions to inventory for forward sales transactions or other reasons or increased expenditures for prepaid items would be reflected as a use of cash and reduce overall cash provided by operating activities in a given reporting period. As these assets are charged to expense in subsequent periods, the expense amount is reflected as a positive change in operating accounts; however, there is no impact on operating cash flows.

In addition to the adjustments noted above, non-cash charges in the income statement are added back to net income and noncash credits are deducted to compute net cash flows provided by operating activities. Examples of noncash charges include depreciation and amortization.

NOTE 20. SELECTED QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008:				
Operating revenues	$ 2,808,488	$ 4,180,463	$ 4,205,744	$ 2,338,194
Operating income	83,519	59,276	59,860	50,765
Net income	64,139	47,682	47,031	34,700
Basic and diluted net income per Limited Partner Unit (1) (2)	$ 0.57	$ 0.42	$ 0.40	$ 0.28

	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

(1) Per Unit calculations include 14,793,329 Units issued in 2008 (4,854,899 Units issued in connection with Cenac acquisition, 378,437 Units issued under the DRIP, 23,097 Units issued under the Unit Purchase Plan, 95,516 net restricted units issued and 9,441,380 Units issued in September 2008) and 106,703 Units issued in 2007 (62,400 restricted units issued, 4,507 Units issued under the Unit Purchase Plan and 39,796 Units issued under the DRIP).

(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 prior to its termination, our Term Credit Facility. TE Products, TCTM, TEPPCO Midstream and Val Verde are collectively referred to as the “Guarantor Subsidiaries.”

The following supplemental condensed consolidating financial information reflects our separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of our other non-guarantor subsidiaries, the combined consolidating adjustments and eliminations and our consolidated accounts for the dates and periods indicated. For purposes of the following consolidating information, our investments in our subsidiaries and the Guarantor Subsidiaries’ investments in their subsidiaries are accounted for under the equity method of accounting. Earnings of subsidiaries are therefore reflected in the Partnership's and Guarantor Subsidiaries' investment accounts and earnings. The elimination entries presented herein eliminate investments in subsidiaries and intercompany balances and transactions.

	December 31, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Assets					
Current assets	$ 23,095	$ 145,146	$ 1,147,976	$ (408,655)	$ 907,562
Property, plant and equipment – net	13,505	1,294,785	1,131,620	--	2,439,910
Equity investments	8,951	1,020,928	226,044	--	1,255,923
Investments	1,685,985	398,946	21	(2,084,952)	--
Intercompany notes receivable	2,628,274	--	--	(2,628,274)	--
Intangible assets	--	117,936	89,717	--	207,653
Goodwill	--	--	106,611	--	106,611
Other assets	14,371	33,373	84,417	--	132,161
Total assets	$ 4,374,181	$ 3,011,114	$ 2,786,406	$ (5,121,881)	$ 5,049,820
Liabilities and partners' capital					
Current liabilities	$ 244,452	$ 215,397	$ 848,802	$ (408,655)	$ 899,996
Long-term debt	2,529,519	--	--	--	2,529,519
Intercompany notes payable	--	1,424,240	1,204,034	(2,628,274)	--
Other long term liabilities	8,731	17,035	3,060	--	28,826
Total partners' capital	1,591,479	1,354,442	730,510	(2,084,952)	1,591,479
Total liabilities and partners' capital	$ 4,374,181	$ 3,011,114	$ 2,786,406	$ (5,121,881)	$ 5,049,820

	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	--	958,345	188,650	--	1,146,995
Investments	1,286,021	388,968	19	(1,675,008)	--
Intercompany notes receivable	1,511,168	--	--	(1,511,168)	--
Intangible assets	--	136,050	28,631	--	164,681
Goodwill	--	--	15,506	--	15,506
Other assets	8,580	34,839	69,895	(62)	113,252
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

	For Year Ended December 31, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating revenues	$ --	$ 383,771	$ 13,149,310	$ (192)	$ 13,532,889
Costs and expenses	--	292,741	12,991,319	(4,593)	13,279,467
Gains (losses) on sales of assets	--	(2)	4	--	2
Operating income	--	91,032	157,987	4,401	253,420
Interest expense – net	--	(83,139)	(56,849)	--	(139,988)
Equity earnings	193,552	175,393	11,693	(297,945)	82,693
Other income	--	959	1,085	--	2,044
Income before provision for income taxes	193,552	184,245	113,916	(293,544)	198,169
Provision for income taxes	--	1,492	3,125	--	4,617
Net income	$ 193,552	$ 182,753	$ 110,791	$ (293,544)	$ 193,552

	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	--	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	--	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, 2008				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
Operating activities:					
Net income	$ 193,552	$ 182,753	$ 110,791	$ (293,544)	$ 193,552
Adjustments to reconcile net income to net cash from operating activities:					
Depreciation and amortization	--	70,457	55,872	--	126,329
Earnings in equity investments	--	(75,401)	(11,693)	4,401	(82,693)
Distributions from equity investments	--	132,295	13,800	--	146,095
Other, net	(71,475)	138,403	(338,563)	235,213	(36,422)
Net cash from operating activities	122,077	448,507	(169,793)	(53,930)	346,861
Cash flows from investing activities:					
Cash used for business combinations	--	--	(351,327)	--	(351,327)
Investment in Jonah	--	(129,759)	--	--	(129,759)
Investment in Texas Offshore Port System	--	--	(35,953)	--	(35,953)
Capital expenditures	--	(193,313)	(98,641)	(8,549)	(300,503)
Other, net	--	(694)	(12,784)	--	(13,478)
Net cash flows from investing activities	--	(323,766)	(498,705)	(8,549)	(831,020)
Cash flows from financing activities:					
Proceeds from term credit facility	1,000,000	--	--	--	1,000,000
Repayments on term credit facility	(1,000,000)	--	--	--	(1,000,000)
Proceeds on revolving credit facility	2,508,089	--	--	--	2,508,089
Repayments on revolving credit facility	(2,481,436)	--	--	--	(2,481,436)
Repayment of debt assumed in Cenac acquisition	--	--	(63,157)	--	(63,157)
Redemption of 7.51% TE Products Senior Notes	--	(181,571)	--	--	(181,571)
Repayment of 6.45% TE Products Senior Notes	--	(180,000)	--	--	(180,000)
Issuance of Limited Partner Units, net	275,856	--	--	--	275,856
Issuance of senior notes	996,349	--	--	--	996,349
Acquisition of treasury units	(9)	--	--	--	(9)
Debt issuance costs	(9,862)	--	--	--	(9,862)
Settlement of treasury lock agreements	(52,098)	--	--	--	(52,098)
Intercompany debt activities	(1,023,002)	564,757	882,971	(424,726)	--
Distributions	(327,997)	(327,997)	(151,316)	479,313	(327,997)
Net cash flows from financing activities	(114,110)	(124,811)	668,498	54,587	484,164
Net change in cash and cash equivalents	7,967	(70)	--	(7,892)	5
Cash and cash equivalents, January 1	8,147	70	22	(8,216)	23
Cash and cash equivalents, December 31	$ 16,114	$ --	$ 22	$ (16,108)	$ 28

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:					
Depreciation and amortization	--	75,377	29,848	--	105,225
Earnings in equity investments	--	(70,664)	(2,602)	4,511	(68,755)
Distributions from equity investments	--	110,500	12,400	--	122,900
Gains in sales of assets	--	(18,653)	--	--	(18,653)
Gain on sale of ownership interest in Mont Belvieu Storage Partners, L.P.	--	(59,628)	--	--	(59,628)
Other, net	(286,162)	(68,940)	56,230	289,175	(9,697)
Net cash from operating activities	(6,982)	247,172	189,319	(78,937)	350,572
Cash flows from investing activities:					
Proceeds from sales of assets	--	26,550	1,234	--	27,784
Proceeds from sale of ownership interest	--	137,326	--	--	137,326
Purchase of assets	--	(6,180)	(6,729)	--	(12,909)
Investment in Centennial	--	(11,081)	--	--	(11,081)
Investment in Jonah	--	(187,547)	--	--	(187,547)
Capital expenditures	--	(153,715)	(74,557)	--	(228,272)
Other, net	--	(18,144)	(24,557)	--	(42,701)
Net cash flows from investing activities	--	(212,791)	(104,609)	--	(317,400)
Cash flows from financing activities:					
Proceeds on revolving credit facility	1,305,750	--	--	--	1,305,750
Repayments on revolving credit facility	(1,305,750)	--	--	--	(1,305,750)
Issuance of Limited Partner Units, net	1,696	--	--	--	1,696
Redemption of portion of 7.51% Senior Notes	--	(36,138)	--	--	(36,138)
Issuance of Junior Subordinated Notes	299,517	--	--	--	299,517
Debt issuance costs	(4,052)	--	--	--	(4,052)
Intercompany debt activities	--	297,512	2,005	(299,517)	--
Distributions	(294,450)	(294,450)	(86,765)	381,215	(294,450)
Other, net	1,443	(1,235)	2	(2)	208
Net cash flows from financing activities	4,154	(34,311)	(84,758)	81,696	(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 operating activities:					
Depreciation and amortization	--	71,100	37,152	--	108,252
Earnings in equity investments	--	(27,034)	(11,905)	2,178	(36,761)
Distributions from equity investments	--	42,965	20,518	--	63,483
Other, net	1,412	(31,926)	(47,279)	13,841	(63,952)
Net cash from operating activities	203,463	257,156	149,544	(337,090)	273,073
Cash flows from investing activities:					
Proceeds from sales of assets	--	11,888	39,670	--	51,558
Purchase of assets	--	(20,473)	--	--	(20,473)
Investment in MB Storage	--	(4,767)	--		(4,767)
Investment in Centennial	--	(2,500)	--	--	(2,500)
Investment in Jonah	--	(121,035)	--	--	(121,035)
Capital expenditures	--	(54,430)	(118,132)	2,516	(170,046)
Intercompany activities	(195,060)	243,823	--	(48,763)	--
Other, net	--	(4,270)	(2,183)	--	(6,453)
Net cash flows from investing activities	(195,060)	48,236	(80,645)	(46,247)	(273,716)
Cash flows from financing activities:					
Proceeds on revolving credit facility	924,125	--	--	--	924,125
Repayments on revolving credit facility	(840,025)	--	--	--	(840,025)
Issuance of Limited Partner Units, net	195,060	--	--	--	195,060
Intercompany debt activities	--	37,219	90,163	(127,382)	--
Distributions	(278,566)	(342,611)	(159,099)	501,710	(278,566)
Net 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

Jonah Gas Gathering Company and Subsidiary

Consolidated Financial Statements for the Years Ended
December 31, 2008, 2007 and 2006, and
Independent Auditors' Report

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, 2008 and 2007, and the related statements of consolidated income, partners' capital and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
March 2, 2009

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5,246	$ 11,459
Accounts receivable, trade	37,361	35,236
Accounts receivable, related parties	470	845
Natural gas imbalances receivable	7,121	4,838
Inventories	2,420	1,717
Other	1,192	1,301
Total current assets	53,810	55,396
PROPERTY, PLANT AND EQUIPMENT, NET	1,022,058	910,398
INTANGIBLE ASSETS (net of accumulated amortization of $86,799 and $74,016)	136,001	148,784
GOODWILL	2,776	2,776
OTHER ASSETS	2,422	3,346
Total assets	$ 1,217,067	$ 1,120,700
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 4,030	$ 8,288
Accounts payable, related parties	10,818	6,973
Natural gas imbalances payable	6,963	5,071
Accrued taxes other than income	3,097	1,464
Other	3,316	749
Total current liabilities	28,224	22,545
OTHER LIABILITIES	378	264
Total liabilities	28,602	22,809
COMMITMENTS AND CONTINGENCIES (see Note 9)		
PARTNERS' CAPITAL	1,188,465	1,097,891
Total liabilities and partners' capital	$ 1,217,067	$ 1,120,700

See Notes to Consolidated Financial Statements.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

STATEMENTS OF CONSOLIDATED INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2008	2007	2006
REVENUES			
Gathering – Natural gas	$ 181,082	$ 135,583	$ 104,415
Sales of natural gas	31,281	63,210	50,866
Other revenue (see Note 2)	20,462	5,353	4,849
Total revenues	232,825	204,146	160,130
COSTS AND EXPENSES			
Purchases of natural gas	30,161	57,189	48,290
Operating expenses	23,015	19,297	12,802
Operating fuel and power (see Note 2)	15,666	6	123
General and administrative expenses	1,086	917	242
Depreciation, amortization and accretion expense	45,709	30,700	19,647
Taxes – other than income taxes	6,345	3,825	2,748
Gains on sales of assets	(227)	--	--
Total costs and expenses	121,755	111,934	83,852
OPERATING INCOME	111,070	92,212	76,278
OTHER INCOME (EXPENSE)			
Interest expense – net	--	--	(6,812)
Other income	721	908	198
Total other income (expense)	721	908	(6,614)
INCOME FROM CONTINUING OPERATIONS	111,791	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	$ 111,791	$ 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,		
	2008	2007	2006
OPERATING ACTIVITIES			
Net income	$ 111,791	$ 93,120	$ 89,033
Adjustments to reconcile net income to net cash provided by continuing operating activities:			
Income from discontinued operations	--	--	(19,369)
Depreciation, amortization and accretion expense	45,709	30,700	19,647
Non-cash portion of interest expense	--	--	174
Gains on sales of assets	(227)	--	--
Net effect of changes in operating accounts	(2,343)	(48)	31,404
Net cash provided by continuing operating activities	154,930	123,772	120,889
Net cash provided by discontinued operations	--	--	1,521
Net cash provided by operating activities	154,930	123,772	122,410
INVESTING ACTIVITIES			
Proceeds from the sales of assets	6,335	--	38,000
Capital expenditures	(101,375)	(37,199)	(51,211)
Net cash used in investing activities	(95,040)	(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	97,829	34,592	20,000
Distributions paid to partners	(163,932)	(109,706)	(98,646)
Net cash used in financing activities	(66,103)	(75,114)	(109,261)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(6,213)	11,459	(62)
CASH AND CASH EQUIVALENTS, JANUARY 1	11,459	--	62
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 5,246	$ 11,459	$ --

See Notes to Consolidated Financial Statements.

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
Net income	--	90,148	21,643	111,791
Contributions from partners	--	115,284	27,431	142,715
Distributions to partners	--	(132,195)	(31,737)	(163,932)
BALANCE AT DECEMBER 31, 2008	$ --	$ 945,365	$ 243,100	$ 1,188,465

See Notes to Consolidated Financial Statements.

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

Note 1. Organization

Jonah Gas Gathering Company ("Jonah"), a Wyoming general partnership, owns a 714 mile natural gas gathering system known as the "Jonah Gas Gathering System" in the Green River Basin of southwestern Wyoming. Jonah has agreements, including fixed term or 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," "our" 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.

We are owned (i) 80.64% by TEPPCO Midstream Companies, LLC ("TEPPCO Midstream"), a subsidiary of TEPPCO Partners, L.P. ("TEPPCO") and (ii) 19.36% by Enterprise Gas Processing, LLC ("EGP"), a subsidiary of Enterprise Products Partners L.P. ("Enterprise"). TEPPCO Midstream and EGP are collectively referred to as the "Partners." Jonah is governed by a management committee comprised of two representatives approved by Enterprise and two representatives approved by TEPPCO, each with equal voting power.   EGP is the operator of the Jonah assets. TEPPCO Midstream, TEPPCO, EGP and Enterprise are all affiliates of EPCO, Inc. ("EPCO"), a privately-held company controlled by Mr. Dan L. Duncan.

We do not directly employ any officers or other persons responsible for managing our operations. Under an amended and restated administrative services agreement ("ASA"), we reimburse EPCO, Inc. ("EPCO"), a privately-held company also controlled by Mr. Duncan, for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits).

Note 2. Summary of Significant Accounting Policies

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

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, 2008 and 2007, 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 liquid investments 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, with input from its legal counsel assesses such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management, with input from its 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, 2008 and 2007, we had no liabilities for loss contingencies.

Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles (“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 we report in our statements 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.

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 gathering 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, we record a payable for the amount due to customers and also record a receivable for the same amount due from connecting pipeline transporters or shippers. If the customers supply less natural gas 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 estimated value of the imbalances upon final settlement.

Operating, General and Administrative Expenses

We reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits). Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. As an affiliate of EPCO and other companies controlled by Mr. Duncan, our transactions and agreements with them are not necessarily on an arm's length basis.

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, to provide a service to some of the producers on the system and for the natural gas imbalances that are settled in-kind. Since we record natural gas imbalances using average market prices, our results are affected by changes in the prices of natural gas. 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.

In 2008, due to environmental restrictions relating to the Jonah system expansions, we began using electric power, instead of producer gas, to power the Jonah system. As a result, we have begun providing our gathering services to customers with varying arrangements for the payment of electricity costs. Substantially all the costs of electricity are directly reimbursed to us by customers under these arrangements and the customer reimbursements are recorded in Other revenue. The costs of electricity are recorded in Operating fuel and power.

Note 3. Recent Accounting Developments

The accounting standard setting bodies have recently issued the following accounting guidance that may affect our future financial statements: Financial Accounting Standards Board ("FASB") Staff Position ("FSP") SFAS 142-3, *Determination of the Useful Life of Intangible Assets* and SFAS No. 157, *Fair Value Measurements*:

FSP No. FAS 142-3, Determination of the Useful Life of Intangible Assets. In April 2008, the FASB issued FSP No. 142-3, which revised the factors that should be considered in developing renewal or extension assumptions used to determine the useful lives of recognized intangible assets under SFAS No. 142, *Goodwill and Other Intangible Assets*. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements.

SFAS No. 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009.

SFAS 157 applies 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 are 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. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

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, 2008 and 2007, respectively.

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, 2008 and 2007. Accumulated amortization was $86.8 million and $74.0 million for the years ended December 31, 2008 and 2007, 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 $12.8 million, $11.5 million and $9.8 million for the years ended December 31, 2008, 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:

2009	$ 12,896
2010	13,570
2011	13,523
2012	13,624
2013	13,409

Note 5. Related Party Transactions

Formation of Joint Venture

Prior to August 1, 2006, Jonah was an indirect wholly owned subsidiary of TEPPCO. TEPPCO Midstream owned a 99.999% interest in Jonah and TEPPCO GP, Inc. (“TEPPCO GP”), a wholly owned subsidiary of TEPPCO, owned a 0.001% interest in Jonah.   Also, TEPPCO Midstream was the sole member of JGM. On August 1, 2006, EGP became a partner by acquiring an interest in Jonah, 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.

In February 2006, Enterprise assumed the management of the Jonah Phase V expansion project and funded the initial costs of the expansion. Beginning August 1, 2006, TEPPCO reimbursed Enterprise for 50% of the expansion costs Enterprise had previously advanced. From August 1, 2006 through July 2007, the Partners equally shared the costs of the Phase V expansion, and EGP 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, the Partners began sharing partnership cash distributions and earnings based upon a formula that took into account the capital contributions of the Partners, including expenditures by TEPPCO prior to the formation of the joint venture and expansion. Based on this formula, at December 31, 2008 and 2007, TEPPCO Midstream’s ownership interest in Jonah was approximately 80.64% and EGP’s ownership interest was approximately 19.36%. Amounts exceeding an agreed upon base cost estimate of $415.2 million were shared 19.36% by EGP and 80.64% by TEPPCO Midstream. Final ownership in Jonah is currently anticipated to remain at these levels. Through December 31, 2008, TEPPCO Midstream has reimbursed EGP $306.5 million ($44.9 million in 2008, $152.2 million in 2007 and $109.4 million in 2006) for TEPPCO Midstream’s 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, 2008 and 2007, TEPPCO Midstream had payables to EGP for costs incurred of $1.0 million and $9.9 million, respectively.

In June 2008, Jonah completed the Phase V expansion, which increased the combined system capacity of the Jonah and Pinedale fields from 1.5 billion cubic feet ("Bcf") per day to 2.35 Bcf per day.

Employees

We have no employees. In conjunction with the 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 our management. The expenses associated with these management and operations services are reflected in costs and expenses in the accompanying statements of consolidated income.

Other

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.

Revenues and expenses from TEPPCO and Enterprise and their respective affiliates and EPCO consist of the following:

	For Year Ended December 31,		
	2008	2007	2006
Revenues and Expenses from TEPPCO and its subsidiaries:			
Sales of natural gas liquids ("NGLs")(1)	$ --	$ --	$ 3,764
Other operating revenues (2)	5,695	5,341	4,622
Operating expense (3)	238	501	--
Revenues and Expenses from Enterprise and its subsidiaries:			
Sales of natural gas (4)	$ 38,254	$ 4,887	$ 8,585
Purchases of natural gas (5)	50	542	251
Gain on sale of Pioneer plant	--	--	17,872
Expenses from EPCO:			
Operating expense (6)	$ 9,940	$ 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. 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 natural gas sales primarily to Enterprise Products Operating LLC, a subsidiary of Enterprise.
(5) Includes processing fees paid to Enterprise for processing services performed at the Pioneer processing plant after its sale to a subsidiary of Enterprise.
(6) 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 consolidated balance sheets consist of the following:

	December 31, 2008			December 31, 2007		
	Accounts Receivable	Accounts Payable	Other Current Liabilities (1)	Accounts Receivable	Accounts Payable	Other Current Liabilities (1)
Partners:						
TEPPCO Midstream and affiliates	$ --	$ 4,748	$ --	$ --	$ 6,033	$ --
EGP and affiliates	470	6,070	70	845	940	1,625
Total	$ 470	$ 10,818	$ 70	$ 845	$ 6,973	$ 1,625

(1) Relates to pipeline imbalances with EGP.

Note 6. Property, Plant and Equipment

Major categories of property, plant and equipment at December 31, 2008 and 2007 were as follows:

	Estimated Useful Life In Years	December 31, 2008	December 31, 2007
Plants and pipelines	5-40(1)	$ 1,024,809	$ 681,772
Underground and other storage facilities	20-40	6,368	6,183
Transportation equipment		837	590
Land and right of way		56,121	54,720
Construction work in progress		25,293	228,686
Total property, plant and equipment		$ 1,113,428	$ 971,951
Less accumulated depreciation		91,370	61,553
Property, plant and equipment, net		$ 1,022,058	$ 910,398

(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 $32.9 million, $19.2 million and $9.8 million for the years ended December 31, 2008, 2007 and 2006, respectively. Depreciation expense for the year ended December 31, 2008 included $2.5 million associated with gathering lines we retired during the year in connection with an ongoing abandonment project. When property, plant and equipment assets are retired or otherwise disposed of, the related costs and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in statements of consolidated income for the period.

Certain producers in the Green River Basin have elected to centralize their natural gas production activities in an effort to reduce operating costs. The producers are responsible for all costs incurred in connection with the centralization activities. These activities eliminate the producers' need for multiple connections to the Jonah Gas Gathering System; however, the producers' centralization activities do not reduce the quantity of natural gas available to the Jonah Gas Gathering System. We are abandoning certain smaller diameter gathering lines (currently estimated to aggregate approximately 42 miles) as a result of the producers' centralization activities. We currently expect $1.3 million of additional depreciation expense in 2009 related to the abandonment of these gathering lines.

On June 1, 2008 Jonah sold assets to a third party for approximately $6.3 million and recognized a gain on sale of assets of approximately $0.2 million.

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, 2008.

Asset Retirement Obligations

We have recorded AROs related to the legal requirements to perform retirement activities as specified in contractual arrangements and/or government regulations. Certain sections of the Jonah Gas Gathering System are constructed across land owned by the Bureau of Land Management ("BLM"). In general, our AROs result from regulatory requirements stipulated by the BLM, which are triggered by the abandonment or reitrement of our pipeline assets. The following table presents information regarding our AROs since December 31, 2006:

ARO liability balance, December 31, 2006	$	191
Liabilities incurred		48
Accretion expense		25
ARO liability balance, December 31, 2007		264
Revisions in estimated cash flows		3,589
Accretion expense		198
Liabilities settled		(1,012)
ARO liability balance, December 31, 2008	$	3,039

During 2008, management revised its cash flow estimates for certain smaller diameter gathering lines that we are abandoning in accordance with the applicable BLM regulations. These gathering lines became idle as a result of producers' efforts to centralize natural gas production thereby triggering abandonment requirements. Our ARO liability for the Jonah Gas Gathering System increased $3.6 million during 2008 due to management's revision in cash flow estimates. We incurred $1.0 million of costs during 2008 to settle retirement obligations associated with abandoned gathering lines. Based on current information, we expect to incur $2.7 million of additional costs during 2009 to abandon additional gathering lines and settle the related obligations.

Property, plant and equipment at December 31, 2008, includes $1.3 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 $26 thousand for 2009, $28 thousand for 2010, $31 thousand for 2011, $34 thousand for 2012 and $37 thousand for 2013.

Note 7. 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 for $38.0 million in cash. We have no continuing involvement in the operations or results of this plant. 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	51
Gain on sale of Pioneer plant	(17,872)
Increase in inventories	(27)
Net cash provided by discontinued operations	$ 1,521

Note 8. 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 Midstream and EGP, our Partnership Agreement was amended and restated. We paid distributions 100% to TEPPCO Midstream 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 our 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 5, the ownership in the joint venture is anticipated to remain approximately 80.64% TEPPCO and approximately 19.36% EGP.

For the year ended December 31, 2008, cash distributions paid to TEPPCO Midstream and EGP totaled $132.2 million and $31.7 million, respectively. For the year ended December 31, 2007, cash distributions paid to TEPPCO Midstream and EGP 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.

For the year ended December 31, 2008, we received contributions of $115.3 million and $27.4 million from 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, 2008, 2007 and 2006, included non-cash contributions related to expansions of the Jonah system of $36.0 million, $153.4 million and $126.8 million, respectively, from TEPPCO Midstream and $8.9 million, $105.5 million and $116.9 million, respectively, from EGP. Additionally, the non-cash contributions 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 the admission of EGP on August 1, 2006. On August 1, 2006, effective with the admission of EGP, the balance in our accounts payable, related parties of $20.9 million was transferred to partners' capital as non-cash contributions.

Note 9. Commitments and Contingencies

Legal Proceedings

In October 2005, 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 failed to conform to quality specifications of the Interconnect and Operator Balancing Agreement ("Interconnect Agreement") which has allegedly caused damages to the Opal Plant in excess of $28 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. Discovery is ongoing.

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 our financial position, results of operations or cash flows.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2008. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
	Total	2009	2010	2011	2012	2013	Thereafter
Operating leases (1)	$ 1,176	$ 134	$ 53	$ 53	$ 58	$ 56	$ 822
Purchase obligations (2)	26,143	3,246	3,246	3,247	3,247	3,247	9,910
Capital expenditure obligations (3)	16,574	16,574	--	--	--	--	--

(1) We use leased assets in several areas of our operations. Total rental expense for the years ended December 31, 2008, 2007 and 2006 were $0.8 million, $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, 2008.

(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 10. 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 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 year ended December 31, 2008, Encana Oil and Gas (USA) Inc., Enterprise, BP Energy Company and Shell Rocky Mountain Production, LLC accounted for 35%, 14%, 12% and 12%, respectively, of our total consolidated revenues. 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, 2008, 2007 and 2006.

Note 11. Supplemental Cash Flow Information

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities and (ii) non-cash financing activities for the years ended December 31, 2008, 2007 and 2006:

	For Year Ended December 31,		
	2008	2007	2006
Decrease (increase) in:			
Accounts receivable, trade	$ (2,125)	$ (10,607)	$ (6,232)
Accounts receivable, related parties	376	1,647	(2,492)
Inventories	(703)	(398)	254
Other current assets	(2,174)	(616)	13,675
Other	242	697	(662)
Increase (decrease) in:			
Accounts payable and accrued liabilities	(1,804)	2,256	(3,202)
Accounts payable, related parties	3,845	6,973	30,113
Other	--	--	(50)
Net effect of changes in operating accounts	$ (2,343)	$ (48)	$ 31,404

JONAH GAS GATHERING COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Non-cash financing activities:						
Non-cash contributions from partners for Expansions of the Jonah System	$	44,886	$	258,919	$	243,718
Liabilities for construction work in progress		143		178		259
Distributions payable to partners		--		--		11,716
Contribution of Note Payable, TEPPCO Midstream		--		--		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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**FIRST AMENDMENT TO THE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY
RETENTION INCENTIVE COMPENSATION PLAN**

WHEREAS, Texas Eastern Products Pipeline Company, LLC (“TEPPCO”) maintains the Texas Eastern Products Pipeline Company Retention Incentive Compensation Plan (the “Plan”); and

WHEREAS, the Plan has been in operational compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, TEPPCO has determined that the Plan should be amended to be in documentary compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, the transition rules of Section 409A provide that TEPPCO has the right to amend the Plan until December 31, 2008 in order to remain in compliance with Section 409A; and

WHEREAS, Section XII of the Plan grants the Board the right to amend the Plan from time to time.

NOW THEREFORE, BE IT RESOLVED, that the Plan is hereby amended as set forth below, effective November 3, 2008**:**

1. Section VII of the Plan is hereby amended in its entirety, to read as follows:

“VII. CREDIT AND REDEMPTION OF PHANTOM UNITS AND LIMITATIONS

A. Phantom Units awarded to a Participant shall be credited to a Participant’s Phantom Unit Account as of the credit date (also called Vesting Date) set forth in the Award Agreement or Phantom Unit Award Certificate and redemption and payment shall automatically occur within 60 days following the date of credit in accordance with such terms and conditions as the Committee shall prescribe.

B. Any Phantom Units that have been awarded, but not credited, to a Participant’s Account shall be deemed forfeited as of the date of the Participant’s retirement or termination of employment for any reason except termination of employment due to death or disability (as defined in Section 409A of the Code and applicable regulatory guidance).

C. Notwithstanding anything to the contrary herein, if the Committee, in its sole discretion, determines that the Participant has an unforeseeable emergency as defined in Treasury Regulation Section 1.409A-3(i)(3) and meets all the conditions as set forth therein, then it shall accelerate the crediting of Phantom Units to the Participant’s Phantom Unit Account and redemption and payment shall occur within 60 days after the occurrence of the unforeseeable emergency. The Committee’s decision as to the determination of an unforeseeable emergency under this paragraph shall be conclusive.

D. The cash value of each Phantom Unit will be based on the Market Value of a Limited Partnership Unit as of the date of credit (also called Vesting Date). The Committee shall establish the necessary procedures for redemption of Phantom Units. Redemption and cash payments under this Plan shall be made no later than 60 days following the credit date of the Phantom Units. Cash payment shall be made to the Participant; provided however, payment upon the death of a Participant shall be made to the Participant’s surviving spouse, or if no surviving spouse exists, to his or her estate or legal representative.

E. Specified Employee Limitation. Notwithstanding any provisions in the Plan or Award Agreement to the contrary, to the extent that the Participant is a “specified employee” (as defined in Section 409A of the Code and applicable regulatory guidance), and any stock or units of TEPPCO (or of any entity that together with TEPPCO is treated as a single employer under Section 414(b) or (c) of the Code), is publicly traded on an established securities market or otherwise, no distribution or payment that is subject to Section 409A of the Code shall be made hereunder on account of a Participant’s “separation from service” (as defined in Section 409A of the Code and applicable regulatory guidance) before the date that it the first day of the month that occurs six months after the date of the Participant’s separation from service (or earlier, the date of death of the Participant or any other date permitted under Section 409A of the Code and applicable regulatory guidance) Any such payments shall be aggregated and paid in a lump sum, without interest.”

2. Section VIII of the Plan is hereby amended in its entirety, to read as follows:

“VIII. QUARTERLY DISTRIBUTIONS

A. As of each quarterly distribution date, and no later than 60 days after each quarterly distribution date, TEPPCO shall pay to each Participant, if he or she is then an Eligible Employee and has not had a termination of employment, an amount equal to the product of:

1. the total number of Phantom Units awarded (whether or not then credited to the Participant’s Phantom Unit Account) to a Participant less the total number of Phantom Units redeemed and paid before the distribution record date, multiplied by

2. the distribution paid with respect to a Limited Partnership Unit for such quarter.

Distribution Equivalents shall be treated separately from the rights to other amounts awarded under the Plan for purposes of designating the time and form of payments under the Plan."

IN WITNESS WHEREOF, TEPPCO has executed this Amendment in its corporate name the 3rd day of November, 2008.

ATTEST:	**TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC**
______________________	By: /s/ JERRY E. THOMPSON Jerry E. Thompson President & Chief Executive Officer

FIRST AMENDMENT TO THE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY
RETENTION INCENTIVE COMPENSATION PLAN
PHANTOM UNIT AWARD AGREEMENT

WHEREAS, Texas Eastern Products Pipeline Company, LLC ("TEPPCO") maintains the Texas Eastern Products Pipeline Company Retention Incentive Compensation Plan (the"Plan"); and

WHEREAS, pursuant to the Plan, TEPPCO has entered into a Phantom Unit Award Agreement (the "Agreement") certain Eligible Employees (the "Participant") setting forth the conditions of the Phantom Unit Award; and

WHEREAS, the Plan and each outstanding Agreement has been in operational compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, TEPPCO has determined that each outstanding Agreement should be amended to be in documentary compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, the transition rules of Section 409A provide that TEPPCO has the right to amend each outstanding Agreement until December 31, 2008 in order to remain in compliance with Section 409A; and

WHEREAS, Section XII of the Plan grants the Board the right to amend the Plan, or any part thereof, from time to time.

NOW THEREFORE, BE IT RESOLVED, that the outstanding Award Agreement to that certain Participant identified below is hereby amended, to read as follows, effective November 3, 2008:

1. Section 5 "Distribution Equivalents" is hereby amended in its entirety, to read as follows:

"5. Distribution Equivalents. As soon as possible, but in no event later than 60 days, after each quarterly distribution date, TEPPCO shall pay to the Participant, if he or she is then an Eligible Employee and has not had a termination of employment, a cash payment equal to the product of:

(a) the total number of Phantom Units awarded to the Participant, reduced by the number of Phantom Units redeemed and paid as of the appropriate distribution record date, multiplied by

(b) the distribution paid with respect to a Limited Partnership Unit for such quarter."

2. Section 6 "Crediting and Redemption of Phantom Units" is hereby amended in its entirety, to read as follows:

"6. Crediting and Redemption of Phantom Units.

(a) Except as otherwise provided in this Section 6, as of the crediting date set forth in the accompanying Certificate (the "Vesting Date"), Participant shall be credited with such portion of the total Phantom Units awarded to the Participant as set forth in the Certificate. Such Phantom Units shall be credited to the Participant's Phantom Unit Account and shall become vested and nonforfeitable.

(b) Redemption and cash payment of the amount of the Phantom Units credited to the Participant's Phantom Unit Account as of the Vesting Date shall automatically occur within 60 days following the Vesting Date.

(c) If the Participant's employment with TEPPCO is terminated, any Phantom Units that have been awarded, but not credited, to Participant's Phantom Unit Account at such time shall be subject to forfeiture in accordance with Section 16 below and the terms of the Plan.

(d) If Participant's employment is terminated due to disability (as defined in Section 409A of the Code and applicable regulatory guidance) or death (collectively, "Severance"), any Phantom Units that have been awarded, but not credited, to a Participant's Phantom Unit Account at such time of any such Severance shall be immediately credited to a Participant's Phantom Unit Account as of the date of such Severance and redemption and payment shall be made within 60 days following the date of such Severance.

(e) Phantom Units will be redeemed in the form of cash payment by TEPPCO. The cash value of each Phantom Unit will be based on the Market Value of a Limited Partnership Unit as of the close of business on the Vesting Date or on the last preceding date on which Market Value can be determined. Redemption and cash payment shall be made no later than 60 days following the Vesting Date. Cash payment shall be made to the Participant, provided however, payment upon the death of a Participant shall be made to the Participant's surviving spouse, or if no surviving spouse exists, to the estate or legal representative.

(f) Notwithstanding anything to the contrary herein, if the Committee, in its sole and absolute discretion, determines that the Participant has an unforeseeable emergency as defined in Treasury Regulation Section 1.409A-3(i)(3) and meets all the conditions as set forth therein, then it shall accelerate the crediting of Phantom Units to the Participant's Phantom Unit Account and redemption and payment shall occur within 60 days after the occurrence of the unforeseeable emergency."

3. Section 7 "Distributions on Account of Death" is hereby deleted in its entirety.

4. Section 17 "Termination of Prior Award" is hereby deleted in its entirety.

5. All references to Sections in the Agreement that would now be inconsistent due to the deletion of Section 7 and 17 are hereby amended to reference the appropriate Section. For example, Section 6(e) references Section 16 in the Agreement. Due to the deletion of Section 7, the reference to Section 16 might be misleading or inconsistent and such reference shall be amended to reference the appropriate Section.

IN WITNESS WHEREOF, TEPPCO has executed this Amendment in its corporate name the 3rd day of November, 2008.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

ATTEST:

____

By: /s/ JERRY E. THOMPSON
Jerry E. Thompson
President & Chief Executive Officer

The Participant hereby agrees to the following Amendment and consents to such changes effective as set forth above.

PARTICIPANT:

____
Name:__________________________

Exhibit 10.13

AMENDMENT TO THE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
2000 LONG TERM INCENTIVE PLAN

WHEREAS, Texas Eastern Products Pipeline Company, LLC ("TEPPCO") maintains the Texas Eastern Products Pipeline Company LLC 2000 LONG TERM INCENTIVE PLAN (the "Plan"); and

WHEREAS, the Plan has been in operational compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, TEPPCO has determined that the Plan should be amended to be in documentary compliance with Section 409A, any exceptions thereo, and the applicable regulatory guidance thereunder; and

WHEREAS, the transition rules of Section 409A provide that TEPPCO has the right to amend the Plan until December 31, 2008 in order to remain in compliance with Section 409A and any exceptions thereto, and

WHEREAS, Section VI of the Plan grants the Board the right to amend the Plan from time to time.

NOW THEREFORE, BE IT RESOLVED, that the Plan is hereby amended as set forth below, effective January 1, 2009:

1. The second paragraph of Section 4.8 of the Plan is hereby amended in its entirety, to read as follows:

"If while Awards remain outstanding under the Plan (a) the Partnership or TEPPCO shall not be the surviving entity in any merger, consolidation or other reorganization (or survives only as a subsidiary of an entity other than an entity that was wholly-owned by the Partnership or TEPPCO immediately prior to such merger, consolidation or other reorganization), (b) the Partnership or TEPPCO sells, leases or exchanges or agrees to sell, lease or exchange all or substantially all of its assets to any other person or entity (other than an entity wholly-owned by the Partnership or TEPPCO), (c) the Partnership or TEPPCO is to be dissolved, or (d) the Partnership or TEPPCO is a party to any other corporate transaction (as defined under Section 424(a) of the Code and applicable Department of Treasury Regulations) that is not described in clauses (a), (b) or (c) of this sentence (each such event is referred to herein as a "Corporate Change"), then (x) except as otherwise provided in an Award Agreement, no later than ten days after the approval by the Partnership or TEPPCO of such Corporate Change, the Board, acting in its sole and absolute discretion without the consent or approval of any Grantee, shall make such adjustments to an Award then outstanding as the Board deems appropriate to reflect such Corporate Change, subject to compliance with the requirements of Section 409A of the Code or if applicable, any exceptions to such provision."

IN WITNESS WHEREOF, TEPPCO has executed this Amendment in its corporate name and its corporate seal to be hereunto fixed the 15th day of December, 2008.

TEXAS EASTERN PRODUCTS
PIPELINE COMPANY, LLC

/s/ Jerry E. Thompson
Jerry E. Thompson
TPPL CEO & President

FIRST AMENDMENT TO THE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC
2005 PHANTOM UNIT PLAN

WHEREAS, Texas Eastern Products Pipeline Company, LLC ("TEPPCO") maintains the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan (the "Plan"); and

WHEREAS, the Plan has been in operational compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, TEPPCO has determined that the Plan should be amended to be in documentary compliance with Section 409A and the applicable regulatory guidance thereunder; and

WHEREAS, the transition rules of Section 409A provide that TEPPCO has the right to amend the Plan until December 31, 2008 in order to remain in compliance with Section 409A; and

WHEREAS, Article VIII of the Plan grants the Board the right to amend the Plan from time to time.

NOW THEREFORE, BE IT RESOLVED, that the Plan is hereby amended as set forth below, effective January 1, 2009:

1. Article V of the Plan is hereby amended in its entirety by revising Section 5.1 and deleting Sections 5.2 and 5.3 to read as follows:

"ARTICLE V. UNIT DISTRIBUTION EQUIVALENT PAYMENTS

5.1 *Quarterly Unit Distribution Equivalent Payments*. Each time quarterly cash distributions are paid to Unit owners and no later than 60 days after such quarterly cash distributions are made, TEPPCO shall pay to each Grantee, if Grantee is then an Employee, in cash, an amount equal to the product of the number of Phantom Units then credited to the Grantee's Account and the amount of the cash distribution paid per Unit by the Partnership. A Grantee shall have no legally binding right to receive any payment pursuant to this Section 5.1 until the date on which the applicable quarterly cash distributions to Unit holders are paid to Unit holders."

IN WITNESS WHEREOF, TEPPCO has executed this Amendment in its corporate name and its corporate seal to be hereunto fixed the 15th day of December, 2008.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY, LLC

/s/ Jerry E. Thompson
Jerry E. Thompson
TPPL CEO & President

TPP Unit Appreciation Right Grant
(Texas Eastern Products Pipeline Company, LLC)

Grant No.	TPP UAR-[______]
Date of Grant:	[________________]
Name of Grantee:	[________________]
Grant Price per Unit:	$[______]
Grant Quarterly DER per Unit:	$[______]
Number of UARs Granted:	[_____________]

EPCO, Inc. (“Company”) is pleased to inform you that you have been granted, under the EPCO, Inc. 2006 TPP Long-Term Incentive Plan, as the same may from time to time hereafter be amended, supplemented or modified (the “Plan”), TPP Unit Appreciation Rights (“UARs”) as set forth above with TPP being TEPPCO Partners, L.P. (“Partnership”). Texas Eastern Products Pipeline Company, LLC (“General Partner”) is the sole general partner of the Partnership. The terms of the Award are as follows:

1. <u>Vesting</u>. The UARs shall become automatically payable on the earlier of (“the “Vesting Date”) (i) the date which is the fifth anniversary of the Date of Grant or (ii) the date on which you have had a Qualifying Event. A “Qualifying Event” means you employment with the Company and its Affiliates is terminated due to your (x) death, (y) being disabled and entitled to receive long-term disability benefits under the Company’s long-term disability plan or (z) retirement with the approval of the Committee on or after reaching age 60. In the event your employment with the Company and its Affiliates terminates for any reason other than a Qualifying Event, the UARs shall automatically and immediately be forfeited and cancelled without payment on such date.

2. <u>No Right to Employment</u>. Nothing in this Award or in the Plan shall confer any right on you to continue employment with the Company or its Affiliates or restrict the Company or its Affiliates from terminating your employment at any time. Employment with an Affiliate shall be deemed to be employment with the Company for purposes of the Plan. Unless you have a separate written employment agreement with the Company or an Affiliate, you are, and shall continue to be, an “at will” employee.

3. <u>UAR Payment</u>. On the Vesting Date, the General Partner will pay you, with respect to each UAR, an amount equal to the excess, if any, of the Fair Market Value of a Unit on the Vesting Date over the Grant Price per Unit. In the sole discretion of the Committee, payment may be made in Units, cash or any combination thereof.

4. <u>DER Payment</u>. Each quarterly distribution date beginning on the distribution date occurring in the quarter immediately succeeding the Grant Date and ending the

quarter immediately preceding the Vesting Date, the General Partner will pay you if you are an employee of EPCO, a cash payment equal to the product of:

(a) the total number of UAR, multiplied by

(b) an amount equal to the excess, if any, of that quarterly distribution paid with respect to a Unit for such quarter over the Grant Quarterly DER per Unit.

5. Transferability. None of the UARs are transferable (by operation of law or otherwise) by you, other than by will or the laws of descent and distribution. If, in the event of your divorce, legal separation or other dissolution of your marriage, your former spouse is awarded ownership of, or an interest in, all or part of the UARs granted hereby to you, the Award shall automatically and immediately be forfeited and cancelled in full without payment on such date.

6. Governing Law. This Award shall be governed by, and construed in accordance with, the laws of the State of Texas, without regard to conflicts of laws principles thereof.

7. Plan Controls. This Award is subject to the terms of the Plan, which is hereby incorporated by reference as if set forth in its entirety herein. In the event of a conflict between the terms of this Award and the Plan, the Plan shall be the controlling document. Capitalized terms which are used, but are not defined, in this Award have the respective meanings provided for in the Plan.

EPCO, Inc.

By: ______________________;___________________
Thomas M. Zulim, Senior Vice President

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)
QP-LS LLC (Wyoming)
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. 333-153314, 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 March 2, 2009, 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, and did not include the internal control over financial reporting of the operations related to the 2008 acquisitions of Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. and Horizon Maritime, L.L.C., appearing in this Annual Report on Form 10-K of TEPPCO Partners, L.P. for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Houston, Texas
March 2, 2009

Exhibit 23.2

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-153314, 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 March 2, 2009, 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. for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Houston, Texas
March 2, 2009

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 TRACY E. OHMART, 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, 2008, 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 23rd day of February, 2009.

/s/ MICHAEL B. BRACY
Michael B. Bracy
Director

/s/ RICHARD S. SNELL
Richard S. Snell
Director

/s/ DONALD H. DAIGLE
Donald H. Daigle
Director

/s/ MURRAY H. HUTCHISON
Murray H. Hutchison
Director

/s/ JERRY E. THOMPSON
Jerry E. Thompson
Director

/s/ TRACY E. OHMART
Tracy E. Ohmart
Acting 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 (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 2, 2009

/s/ JERRY E. THOMPSON
Jerry E. Thompson
President and Chief Executive Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

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, Tracy E. Ohmart, 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 (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 2, 2009

/s/ TRACY E. OHMART
Tracy E. Ohmart
Acting Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC,
as General Partner

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, 2008 (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

March 2, 2009

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, 2008 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Tracy E. Ohmart, Acting 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/ TRACY E. OHMART
Tracy E. Ohmart
Acting Chief Financial Officer
Texas Eastern Products Pipeline Company, LLC, General Partner

March 2, 2009

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 12.1
Statement of Computation of Ratio of Earnings to Fixed Charges

	2004	2005	2006	2007	2008
			(in thousands)		
Earnings					
Income From Continuing Operations *	112,658	138,639	158,538	132,701	115,476
Fixed Charges	80,695	93,414	101,905	119,603	165,832
Distributed Income of					
Equity Investment	47,213	37,085	63,483	122,900	146,095
Capitalized Interest	(4,227)	(6,759)	(10,681)	(11,030)	(19,170)
Total Earnings	236,339	262,379	313,245	364,174	408,233
Fixed Charges					
Interest Expense	72,053	81,861	86,171	101,223	139,988
Capitalized Interest	4,227	6,759	10,681	11,030	19,170
Rental Interest Factor	4,415	4,794	5,053	7,350	6,674
Total Fixed Charges	80,695	93,414	101,905	119,603	165,832
Ratio: Earnings / Fixed Charges	2.93	2.81	3.07	3.04	2.46

* Excludes discontinued operations, gain on sale of assets, provision for income taxes and equity earnings.