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, 2009

OR

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

For the transition period from ___ to ___.

Commission file number: 1-32610

ENTERPRISE GP HOLDINGS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**13-4297064**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1100 Louisiana Street, 10th Floor, Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☑ 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 whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes o 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ 60;
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 Exchange Act). Yes o No ☑

The aggregate market value of Enterprise GP Holdings L.P.'s (or "EPE's") Units held by non-affiliates at June 30, 2009 was approximately $774.7 million, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange. This figure excludes Units beneficially owned by certain affiliates, including Dan L. Duncan. There were 139,191,640 Units of EPE outstanding at February 1, 2010.

ENTERPRISE GP HOLDINGS L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise GP Holdings" or the "Partnership" are intended to mean the business and operations of Enterprise GP Holdings L.P. and its consolidated subsidiaries.

References to the "Parent Company" mean Enterprise GP Holdings L.P., individually as the parent company, and not on a consolidated basis. The Parent Company is owned 99.99% by its limited partners and 0.01% by its general partner, EPE Holdings, LLC ("EPE Holdings"). EPE Holdings is a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan.

References to "Enterprise Products Partners" mean Enterprise Products Partners L.P., a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD," and its consolidated subsidiaries. Enterprise Products Partners has no business activities outside those conducted by Enterprise Products Operating LLC ("EPO"). On October 26, 2009, TEPPCO Partners, L.P. ("TEPPCO") and Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP") merged with Enterprise Products Partners (such related mergers referred to herein individually and together as the "TEPPCO Merger"). References to "EPGP" refer to Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. EPGP is owned by the Parent Company.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). The Parent Company owns noncontrolling interests in both Energy Transfer Equity and LE GP that it accounts for using the equity method of accounting.

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. The Parent Company, EPE Holdings, Enterprise Products Partners, EPO, EPGP, Duncan Energy Partners and DEP GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO. We do not control Energy Transfer Equity or LE GP.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are privately held affiliates of EPCO.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2009 ("annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, *uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by 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.*

PART I

Items 1 and 2. *Business and Properties*.

General

Enterprise GP Holdings L.P. is a publicly traded Delaware limited partnership, the limited partnership interests (the "Units") of which are listed on the NYSE under the ticker symbol "EPE." Our business consists of the ownership of general and limited partner interests of publicly traded partnerships engaged in the midstream energy industry and related businesses. Our goal is to increase cash distributions to unitholders. Our principal executive offices are located at 1100 Louisiana Street, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website address is www.enterprisegp.com.

Business Strategy

The primary objective of the Parent Company is to increase cash available for distributions to its unitholders. There has been significant demand for the development of new midstream energy infrastructure to meet the needs of producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and refined products. In addition, there have been several transactions involving the sale of general partner interests in publicly traded partnerships. Finally, in recent years, major independent oil and gas and other energy companies have divested significant midstream assets. These trends are generally expected to continue. The Parent Company seeks to capitalize on these trends by:

- managing the operations and activities of Enterprise Products Partners for the successful execution of its business strategy;
- evaluating opportunities to acquire general partner interests and, if applicable, associated incentive distribution rights ("IDRs"), and related limited partner interests in publicly traded partnerships (e.g., Energy Transfer Equity and LE GP); and
- evaluating opportunities to acquire other assets and businesses in accordance with business opportunity agreements.

For information regarding our business opportunity agreements, see Item 13 of this annual report.

Financial Information by Business Segment

For detailed financial information regarding our business segments, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion.

Significant Recent Developments

On October 26, 2009, the related mergers of wholly owned subsidiaries of Enterprise Products Partners with TEPPCO and TEPPCO GP were completed (collectively, we refer to these transactions as the "TEPPCO Merger"). Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 common units of Enterprise Products

Partners for each TEPPCO unit. In total, Enterprise Products Partners issued an aggregate of 126,932,318 common units and 4,520,431 Class B units in connection with the TEPPCO Merger as consideration for both the TEPPCO units and TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP," have been delisted and are no longer publicly traded. On October 27, 2009, the TEPPCO and TEPPCO GP equity interests were contributed by Enterprise Products Partners to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

For additional information regarding the TEPPCO Merger and other developments during 2009, see "Significant Recent Developments" included under Item 7 of this annual report, which is incorporated by reference into this Item 1 and 2 discussion.

Basis of Presentation

Our consolidated financial statements and business segments were recast in connection with the TEPPCO Merger. See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the basis for presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 1 and 2 discussion.

Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have six reportable business segments:

§ NGL Pipelines & Services;

§ Onshore Natural Gas Pipelines & Services;

§ Onshore Crude Oil Pipelines & Services;

§ Offshore Pipelines & Services;

§ Petrochemical & Refined Products Services; and

§ Other Investments.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, properties owned, seasonality and competition. Our results of operations and financial condition are subject to a variety of risks. For information regarding our risk factors, see Item 1A of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1 and 2.

Our consolidated revenues are derived from a wide customer base. During 2009, our largest non-affiliated customer based on revenues was Shell Oil Company and its affiliates ("Shell"), which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero Energy Corporation and its affiliates ("Valero"), which accounted for 11.2% and 8.9%, respectively, of our revenues.

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

/d	*= per day*
BBtus	*= billion British thermal units*
Bcf	*= billion cubic feet*
Lbs	*= pounds*
MBPD	*= thousand barrels per day*
MBbls	*= thousand barrels*
MMBbls	*= million barrels*
MMBtus	*= million British thermal units*
MMcf	*= million cubic feet*

For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 of this annual report. In addition, certain of our operations entail the use of derivative instruments. For information regarding our use of commodity derivative instruments, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines aggregating approximately 16,300 miles; (iii) NGL and related product storage and terminal facilities with 163.4 MMBbls of working storage capacity and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to produce isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, and is used in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 25 processing plants located across Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of NGLs. This rich natural gas in its raw form is usually not acceptable for transportation in the nation's natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove NGLs from the natural gas stream, which enables the natural gas to meet pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of a natural gas stream. After extraction by the processing plants, we typically transport the mixed NGLs to a centralized facility for fractionation into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing business, we enter into percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms), keepwhole contracts and margin-band contracts. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to a percentage of the mixed NGLs we extract and generally bears the cost of natural gas associated with shrinkage and plant fuel. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing natural gas at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs in which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our keepwhole and margin-band gas processing contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts typically contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and spot and contract purchases from third parties. These sales contracts may also include forward product sales contracts. In general, sales prices referenced in the contracts utilized within our NGL marketing activities are market-based and may include pricing differentials for such factors as delivery location. The majority of our consolidated revenues and costs and expenses are generated from marketing activities, including those associated with NGLs. Changes in our consolidated revenues and operating costs and expenses period-to-period are explained in part by changes in market prices for the products we sell. The results of operations from our NGL marketing activities are generally dependent upon the volume of products sold and the sales prices charged to customers. The volume of products sold may fluctuate from period-to-period depending on market conditions, volumes produced and opportunities, which may be influenced by current and forward market prices for purity NGL products and our hedging activities.

Our NGL marketing activities include production and purchases of inventories of mixed NGLs and purity NGL products. As a result of exceptional energy market conditions during 2009, we significantly increased our physical NGL inventory purchases and related forward physical sales commitments. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets. Our inventories of ethane, propane and normal butane are typically at higher levels from March through November since these products are normally in higher demand and at higher price levels during the winter months. Isobutane and natural gasoline inventories are generally stable and less cyclical throughout the year. Generally, our inventory cycle begins in late-February to mid-March (the seasonal low point), building through September, and remaining level until early December before being drawn down through winter until the seasonal low is reached again.

For additional information regarding our inventories and consolidated segment revenues and expenses, see Notes 7 and 14, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

NGL pipelines, storage facilities and import/export terminals. Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect purity NGL products to and from fractionation plants, petrochemical plants and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenues from our NGL pipeline transportation agreements are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Excluding inventories held in connection with our marketing activities, we typically do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. However, we occasionally act as shipper for certain volumes being transported.

Our NGL and related product storage facilities are integral parts of our operations used for the storage of products owned by us and our customers. In general, our underground salt dome storage caverns (or wells) are used to store mixed NGLs, purity NGL products and petrochemical products. We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. The customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge other customers throughput fees based on volumes delivered into and subsequently withdrawn from storage. Accordingly, the profitability of our storage operations is dependent upon the level of storage capacity reserved by customers, the volume of product delivered into and withdrawn from the underground caverns and the level of throughput fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas and an NGL terminal in Providence, Rhode Island with ship unloading capabilities. Our NGL import facility is primarily used to offload volumes for delivery to our storage and fractionation facilities located in Mont Belvieu, Texas. Our NGL export facility is used for loading refrigerated marine tankers for customers. Revenues from our terminal services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments if terminaling contracts are cancelled. Accordingly, the profitability of our NGL terminal activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in 11 NGL fractionation facilities located in Texas, Louisiana, Colorado and Ohio. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The primary sources of mixed NGLs fractionated in the United States are domestic natural gas processing plants and crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck to NGL fractionation facilities.

Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast, Rocky Mountain and Midcontinent natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to be processed by our NGL fractionation facilities by joint owners and third-party customers.

Our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities. We typically earn revenues from NGL fractionation under fee-based arrangements. These fees (usually stated in cents per gallon) are contractually subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility in Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based fractionation customers retain title to the NGLs that we process for them. To the extent we fractionate volumes for customers under percent-of-liquids contracts, we are exposed to fluctuations in NGL prices (i.e., commodity price risk). Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments such as forward sales contracts.

Seasonality. Our natural gas processing and NGL fractionation operations typically exhibit little to no seasonal variation. NGL pipeline transportation volumes are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending into motor gasoline). With respect to our NGL and related product storage facilities, we usually experience an increase in demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn down for heating needs. Likewise, the revenues we recognize from NGL marketing activities are predicated on the overall demand for such products, which may fluctuate due to seasonal needs for gasoline blending feedstocks, heating requirements and similar factors. In general, our import volumes peak during the spring and summer months and our export volumes are typically at their highest levels during the winter months. Lastly, our facilities located along the Gulf Coast of the United States may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our natural gas processing business activities and related NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, financial institutions with trading platforms and independent processors. Each of our marketing competitors has varying levels of financial and personnel resources, and competition generally revolves around price, quality of customer service and proximity to customers and other market hubs. In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate pipeline companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and quality of customer service.

Our primary competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections provided and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading throughput capacity.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Competition for such services is primarily based on the fractionation fee charged. However, the ability of an NGL fractionator to receive a customer’s mixed NGLs and store and distribute its purity NGL products is also an important competitive factor and is a function of having the necessary pipeline and storage infrastructure.

Properties. The following table summarizes the significant natural gas processing assets included in our NGL Pipelines & Services business segment at February 1, 2010.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Meeker (2)	Colorado	100%	1.70	1.70
Pioneer	Wyoming	100%	1.35	1.35
Toca	Louisiana	67.4%	0.70	1.10
Chaco	New Mexico	100%	0.65	0.65
North Terrebonne	Louisiana	56.4%	0.73	1.30
Calumet	Louisiana	35.4%	0.57	1.60
Neptune	Louisiana	66%	0.43	0.65
Pascagoula	Mississippi	40%	0.40	1.50
Yscloskey	Louisiana	13.9%	0.26	1.85
Thompsonville	Texas	100%	0.33	0.33
Shoup	Texas	100%	0.29	0.29
Gilmore	Texas	100%	0.25	0.25
Armstrong	Texas	100%	0.25	0.25
Others (11 facilities) (3)	Texas, New Mexico, Louisiana	Various (4)	1.27	2.93
Total processing capacities			9.18	15.75

(1) The approximate net gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) We commenced natural gas processing operations at our Meeker facility in October 2007 and subsequently began the Meeker Phase II expansion project to double the natural gas processing capacity to 1.7 Bcf/d at this facility. The Meeker Phase II expansion became operational during March 2009.
(3) Other natural gas processing facilities include our Venice, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin, Carlsbad and Chaparral facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").
(4) Our ownership in these facilities ranges from 13.1% to 100%.

Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Meeker, Pioneer, Toca, Chaco, North Terrebonne, Calumet, Neptune, Burns Point, Carlsbad and Chaparral plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 48.3%, 52.4% and 51.5% during the years ended December 31, 2009, 2008 and 2007, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 600 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

The following table summarizes the significant NGL pipelines and related storage assets included in our NGL Pipelines & Services business segment at February 1, 2010.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100%	7,832	
Seminole Pipeline	Texas	90% (1)	1,346	
South Texas NGL System	Texas	100% (2)	1,317	
Dixie Pipeline	South and Southeastern U.S.	100%	1,306	
Chaparral NGL System (3)	Texas, New Mexico	100%	1,010	
Louisiana Pipeline System	Louisiana	Various (4)	827	
Skelly-Belvieu Pipeline	Texas	50% (5)	572	
Promix NGL Gathering System	Louisiana	50% (6)	364	
Houston Ship Channel	Texas	100%	254	
Rio Grande Pipeline	Texas	70% (7)	249	
Lou-Tex NGL Pipeline	Texas, Louisiana	100%	205	
Others (11 systems) (8)	Various	Various	1,013	
Total miles			16,295	
NGL and related product storage capacity by state:				
Texas (9)				124.4
Louisiana				15.2
Kansas				8.4
Mississippi				5.8
Others (10)				9.6
Total working capacity (11)				163.4

(1) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company ("Seminole").
(2) The ownership interest presented reflects consolidated ownership of these systems by EPO (34%) and Duncan Energy Partners (66%).
(3) The Chaparral NGL System includes the 180-mile Quanah Pipeline, which begins in Sutton County, Texas, and connects to the Chaparral Pipeline near Midland, Texas.
(4) Of the 827 total miles for this system, we own 100% of 774 miles and 52.5% of the remaining 53 miles.
(5) Our ownership interest in this pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu").
(6) Our ownership interest in this pipeline system is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").
(7) We hold a 70% interest in this system through a majority owned subsidiary, Rio Grande Pipeline Company ("Rio Grande"). We acquired our ownership interest in Rio Grande in December 2009.
(8) Includes our Tri-States, Belle Rose, Wilprise, Chunchula, Bay Area and South Dean pipelines located in the coastal regions of Alabama, Louisiana, Mississippi and Texas; Port Arthur, Wilcox, Panola and San Jacinto pipelines located in east Texas; and our Meeker pipeline in Colorado.
(9) The amount shown for Texas includes 34 underground NGL and petrochemical storage caverns with an aggregate working capacity of approximately 100 MMBbls that are owned by EPO (34%) and Duncan Energy Partners (66%). These 34 caverns are located in Mont Belvieu, Texas.
(10) Includes storage capacity at our facilities in Alabama, Arizona, California, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota and Wisconsin.
(11) Our underground storage caverns and above ground storage tanks have an aggregate 163.4 MMBbls of total working storage capacity, which includes 23.4 MMBbls held under long-term operating leases. The leased facilities are located in Indiana, Kansas, Louisiana, South Dakota and Texas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products being shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,099 MBPD, 1,948 MBPD and 1,794 MBPD during the years ended December 31, 2009, 2008 and 2007, respectively.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Skelly-Belvieu Pipeline, Tri-States and a small portion of the Louisiana Pipeline System.

§ The *Mid-America Pipeline System* is a regulated NGL pipeline system consisting of three primary segments: the 2,793-mile Rocky Mountain pipeline, the 2,773-mile Conway North pipeline and the 2,266-mile Conway South pipeline. This system is present in 13 states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third-party connections. The Conway South pipeline connects the Conway hub with Kansas refineries and transports NGLs to and from Conway, Kansas to the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. This system includes 15 unregulated propane terminals.

During 2009, approximately 50% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants. The remaining volumes consisted of purity NGL products originating from NGL fractionators located in Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

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

§ The *South Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system gathers and transports mixed NGLs from our south Texas natural gas processing plants to our south Texas NGL fractionation facilities. In turn, the system transports NGLs from our south Texas NGL fractionation facilities to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with common carrier NGL pipelines.

§ The *Dixie Pipeline* is a regulated pipeline that extends from southeast Texas and Louisiana to markets in the southeastern United States and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. This system includes eight unregulated propane terminals and operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

§ The *Chaparral NGL System* transports NGLs from natural gas processing plants in west Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 830-mile regulated Chaparral pipeline and the 180-mile unregulated Quanah pipeline.

§ The *Louisiana Pipeline System* is a network of NGL pipelines located in south Louisiana. This system transports NGLs originating in Louisiana and Texas to refineries and petrochemical companies located along the Mississippi River corridor in south Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other assets located in Louisiana. In December 2009, we acquired 215 miles of intrastate pipelines from Chevron Midstream Pipelines LLC that expand and extend our Louisiana Pipeline System. Originating from a central point in Henry, Louisiana, the acquired pipelines extend westward to Lake Charles, northward to an interconnect with the Dixie Pipeline at Breaux Bridge, and eastward to Napoleonville, Louisiana, where our Promix NGL fractionation and storage facilities are located.

- The *Skelly-Belvieu Pipeline* is a regulated pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. We anticipate becoming operator of this pipeline by January 1, 2011.

- The *Promix NGL Gathering System* gathers mixed NGLs from natural gas processing plants in south Louisiana for delivery to our Promix NGL fractionator.

- The *Houston Ship Channel* pipeline system connects our Mont Belvieu, Texas facilities with our Houston Ship Channel import/export terminals and various third-party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

- The *Rio Grande Pipeline* is a regulated pipeline originating near Odessa, Texas that transports mixed NGLs to a pipeline interconnect at the Mexican border south of El Paso, Texas.

- The *Lou-Tex NGL Pipeline* system transports NGLs and refinery grade propylene between the Louisiana and Texas markets.

Our NGL and related product storage and terminal facilities are integral components of our midstream energy infrastructure. We operate these storage and terminal facilities, with the exception of certain Louisiana storage locations that are operated for us by a third-party.

Our largest underground storage facility is located in Mont Belvieu, Texas and is owned 66% by Duncan Energy Partners and 34% by EPO. This storage facility consists of 34 underground NGL and petrochemical salt dome storage caverns with an aggregate working storage capacity of approximately 100 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast.

The following table summarizes the significant NGL fractionation assets included in our NGL Pipelines & Services business segment at February 1, 2010.

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	75% (2)	178	230
Shoup and Armstrong	Texas	100% (3)	82	82
Hobbs	Texas	100%	75	75
Norco	Louisiana	100%	75	75
Promix	Louisiana	50% (4)	73	145
BRF	Louisiana	32.2% (5)	19	60
Tebone	Louisiana	56.4% (2)	12	30
Other (6)	Colorado, Ohio	100%	15	15
Total plant capacities			529	712

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) Ownership interests presented reflect direct consolidated interests in each facility.
(3) The ownership interest presented reflects consolidated ownership of these plants by EPO (34%) and Duncan Energy Partners (66%).
(4) Our ownership interest in this facility is held indirectly through our equity method investment in Promix.
(5) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(6) Consists of two NGL fractionation facilities located in northeast Colorado and a fractionation facility located near Todhunter, Ohio.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities, with the exception of our two Colorado fractionators.

§ Our *Mont Belvieu* NGL fractionation facility is located in Mont Belvieu, Texas, which is a key hub of the NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountains, east Texas and the Gulf Coast.

In August 2009, we announced plans to build a new 75 MBPD NGL fractionator at our Mont Belvieu facility that will provide us with additional capacity to process growing NGL volumes from producing areas in the Rockies, the Barnett Shale and the emerging Eagle Ford Shale supply basin in south Texas. This growth capital project will increase our gross NGL fractionation capacity at Mont Belvieu to approximately 305 MBPD. The project is expected to be completed in the first quarter of 2011.

§ Our *Shoup* and *Armstrong* fractionators process mixed NGLs supplied by our south Texas natural gas processing plants. Purity NGL products from the Shoup and Armstrong fractionators are transported to local markets in the Corpus Christi area and also to Mont Belvieu, Texas using our South Texas NGL Pipeline System.

§ Our *Hobbs* NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical plants and refineries in west Texas, New Mexico, California and northern Mexico. The Hobbs facility receives mixed NGLs from several major supply basins including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

§ Our *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants located in south Louisiana and along the Mississippi and Alabama Gulf Coast, including from our Yscloskey, Pascagoula, Venice and Toca facilities.

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

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

On a weighted-average basis, utilization rates for our NGL fractionators were 88.8%, 83.6% and 78% during the years ended December 31, 2009, 2008 and 2007, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP. Our import facility can offload NGLs from tanker vessels at rates up to 20,000 barrels per hour depending on the product. Our export facility can load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. In addition to these facilities, we own a barge dock also located on the Houston Ship Channel that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. We also own an NGL terminal in Providence, Rhode Island that includes 0.4 MMBbls of refrigerated tank storage capacity and ship unloading capabilities at rates up to 11,800 barrels per hour. Our average combined NGL import and export volumes were 98 MBPD, 74 MBPD and 84 MBPD for the years ended December 31, 2009, 2008 and 2007, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 19,200 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our related natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing activities. Our onshore natural gas pipeline systems provide for the gathering and transportation of natural gas from major producing regions such as the San Juan, Barnett Shale, Permian, Piceance, Greater Green River and Eagle Ford supply basins in the western United States. In addition, certain of these systems receive natural gas production from the Gulf of Mexico through coastal pipeline interconnects with offshore pipelines. Our onshore natural gas pipelines receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers, or to other onshore pipelines.

Our onshore natural gas pipelines typically generate revenues from transportation agreements whereby shippers are billed a fee per unit of volume transported (typically per MMBtu) multiplied by the volume gathered or delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity reserved in our pipelines whether or not the shipper actually utilizes such capacity. In connection with our natural gas transportation services and marketing activities, intrastate natural gas pipelines (such as our Acadian Gas System) may also purchase natural gas from producers and other suppliers for transport and resale to customers such as electric utility companies, local natural gas distribution companies, industrial users and other natural gas marketing companies.

Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained from third-party well-head purchases, regional natural gas processing plants and the open market. In general, sales prices referenced in the contracts utilized within our natural gas marketing activities are market-based and may include pricing differentials for such factors as delivery location. We entered the natural gas marketing business in an effort to maximize the utilization of our portfolio of natural gas pipeline and storage assets. We expect our natural gas marketing business to continue to expand in the future. The results of operations for our onshore natural gas pipelines and related marketing activities are generally dependent upon the volume of natural gas transported and/or sold and amounts charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements).

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with certain intrastate natural gas transportation contracts and our natural gas marketing activities. In addition, we purchase and resell natural gas for certain producers that use our San Juan, Carlsbad and Jonah Gathering Systems and certain segments of our Texas Intrastate System. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to fluctuations in commodity prices through transportation arrangements with shippers. For example, nearly all of the transportation revenues generated by our San Juan Gathering System are based on a percentage of a regional price index for natural gas. This index is subject to change based on a variety of factors including natural gas supply and consumer demand. We use derivative instruments to mitigate our exposure to commodity price risks associated with our natural gas pipelines and services business.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage ("Petal") and

Hattiesburg Gas Storage locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into six interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

Our natural gas storage facilities are designed for sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal modes of operation. The ability of underground salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond quickly in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities.

Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with a customer's storage capacity reservation and paid regardless of actual usage, and (ii) storage fees per unit of volume stored at our facilities.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation utilities increase their output to meet residential and commercial demand for electricity used for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is used to meet residential and commercial heating requirements. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

Competition. Within their market areas, our onshore natural gas pipelines compete with other natural gas pipelines on the basis of price (in terms of transportation fees), quality of customer service and operational flexibility. Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. Our natural gas marketing activities compete primarily with other natural gas pipeline companies and their marketing affiliates and financial institutions with trading platforms. Competition in the natural gas marketing business is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Properties. The following table summarizes the significant assets included in our Onshore Natural Gas Pipelines & Services business segment at February 1, 2010.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100% (1)	8,051	6,640	
Jonah Gathering System	Wyoming	100%	849	2,550	
Piceance Basin Gathering System	Colorado	100%	102	1,600	
White River Hub	Colorado	50%	10	1,500	
San Juan Gathering System	New Mexico, Colorado	100%	6,070	1,200	
Acadian Gas System	Louisiana	Various (2)	1,041	1,149	
Val Verde Gas Gathering System	New Mexico, Colorado	100%	420	550	
Carlsbad Gathering System	Texas, New Mexico	100%	919	220	
Alabama Intrastate System	Alabama	100%	408	200	
Encinal Gathering System	Texas	100%	535	143	
Other (6 systems) (3)	Texas, Mississippi	Various (4)	785	1,840	
Total miles			19,190		
Natural gas storage facilities:					
Petal	Mississippi	100%			16.6
Hattiesburg	Mississippi	100%			2.1
Wilson	Texas	Leased (5)			6.8
Acadian	Louisiana	Leased (6)			1.3
Total gross capacity					26.8

(1) In general, our consolidated ownership of this system is 100% through interests held by EPO and Duncan Energy Partners. We own and operate a 50% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100% undivided interest in and lease certain segments of the Enterprise Texas pipeline system, which is a component of the Texas Intrastate System.

(2) Our ownership interest reflects consolidated ownership of Acadian Gas by EPO (34%) and Duncan Energy Partners (66%). Amounts presented include the 49.5% equity method investment that Acadian Gas has in the 27-mile Evangeline pipeline.

(3) Includes the Delmita, Big Thicket, Indian Springs and Canales gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. The Petal and Hattiesburg pipelines, which have a combined capacity in excess of 1.4 MMcf/d, are integral components of our Petal and Hattiesburg natural gas storage operations.

(4) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% undivided interest through a consolidated subsidiary. Our 100% ownership interest in Big Thicket reflects consolidated ownership by EPO (34%) and Duncan Energy Partners (66%).

(5) We hold this facility under an operating lease that expires in January 2028.

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

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 64.4%, 68.7% and 67.0% during the years ended December 31, 2009, 2008 and 2007, respectively. The utilization rate for 2008 excludes the White River Hub, which commenced operations during December 2008. The utilization rate for 2007 excludes our Piceance Basin Gathering System, which operated at an average utilization rate of 24.3% during 2007 as volumes ramped-up on this system. Our utilization rates reflect the periods in which we owned an interest in such assets or, for recently constructed assets, since the dates such assets were placed into service.

The following information highlights the general use of each of our principal onshore natural gas pipelines. With the exception of the White River Hub and certain minor segments of the Texas Intrastate System, we operate our onshore natural gas pipelines and storage facilities.

§ The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System is comprised of the 6,560-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 660-mile Waha gathering system and the 190-mile TPC Offshore gathering system. The Enterprise Texas pipeline system includes a 263-mile pipeline we lease from an affiliate of ETP. The leased Wilson natural gas storage facility located in Wharton County, Texas is an integral part of the Texas Intrastate System. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

The 173-mile Sherman Extension pipeline, which is part of our Texas Intrastate System, was completed in late February 2009 and is capable of transporting up to 1.2 Bcf/d of natural gas from the prolific Barnett Shale production basin in north Texas. The Sherman Extension provides producers with connections to third-party interstate pipelines having access to markets outside of Texas. An aggregate of 1.0 Bcf/d of the Sherman Extension's throughput capacity has been contracted for by customers, including EPO, under long-term contracts.

In late 2008, we began design of the 40-mile Trinity River Lateral, which is expected to be completed during the second quarter of 2010. The Trinity River Lateral will be capable of transporting up to 1.0 Bcf/d of natural gas and will provide producers in the Barnett Shale production basin with additional takeaway capacity. We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in 2010. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of natural gas storage capacity.

§ The *Jonah Gathering System* is located in the Greater Green River Basin of southwest Wyoming. This system gathers natural gas from the Jonah and Pinedale supply basins for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate pipelines. In mid-2009, we completed an expansion of that portion of the system that serves the Pinedale field, which increased total capacity of the Jonah Gathering System from 2.35 Bcf/d to 2.55 Bcf/d.

§ The *Piceance Basin Gathering System* consists of the 48-mile Piceance Creek, 32-mile Great Divide and 22-mile Collbran Valley gathering systems located in the Piceance Basin of northwestern Colorado. The Piceance Creek gathering system extends from a connection with the Great Divide gathering system to our Meeker natural gas processing plant. The Great Divide gathering system gathers natural gas from the southern portion of the Piceance Basin, including natural gas gathered on the Collbran Valley gathering system, to an interconnect with our Piceance Creek gathering system.

§ The *White River Hub* is a regulated interstate natural gas transportation hub facility. The White River Hub connects to six interstate natural gas pipelines in northwest Colorado and has a gross capacity of 3 Bcf/d of natural gas (1.5 Bcf/d net to our 50% ownership interest). White River Hub began service in December 2008.

§ The *San Juan Gathering System* serves producers in the San Juan Basin of north New Mexico and south Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas to regional processing facilities, including our Chaco natural gas processing plant located in New Mexico.

§ The *Acadian Gas System* purchases, transports, stores and resells natural gas in south Louisiana. The Acadian Gas System is comprised of the 576-mile Cypress pipeline, the 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The Acadian Gas System includes a leased natural gas storage facility at Napoleonville, Louisiana that is an integral part of its pipeline operations.

In October 2009, we and Duncan Energy Partners announced plans to extend our Acadian Gas System into the rapidly growing Haynesville Shale supply basin in northwest Louisiana. Our 249-mile Haynesville Extension pipeline will have transportation capacity of up to 2.1 Bcf/d of natural gas and will extend from the Haynesville region to interconnects with interstate pipelines in central Louisiana and with our existing Acadian Gas System. The pipeline is expected to be placed into service during the third quarter of 2011.

The Haynesville Extension will provide producers in the Haynesville Shale supply basin with takeaway capacity, including access to more than 150 end-use markets along the Mississippi River corridor between Baton Rouge and New Orleans, Louisiana. In addition, shippers will be able to access our Napoleonville salt dome storage cavern and have the ability to make physical deliveries into the Henry Hub and benefit from more favorable pricing points. The Haynesville Extension will also allow shippers to reach nine interstate pipeline systems.

§ The *Val Verde Gas Gathering System* gathers natural gas, including coal bed methane from the Fruitland Coal Formation in the San Juan Basin, from producing regions in north New Mexico and south Colorado.

§ The C*arlsbad Gathering System* gathers natural gas from the Permian Basin region of Texas and New Mexico for delivery into the El Paso Natural Gas, Transwestern and Oasis pipelines.

§ The *Alabama Intrastate System* gathers natural gas, primarily coal bed methane, from the Black Warrior supply basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

§ The *Encinal Gathering System* gathers natural gas from the Olmos, Wilcox and Eagle Ford formations in south Texas for processing at our south Texas natural gas processing plants.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 4,400 miles of onshore crude oil pipelines and 10.5 MMBbls of above-ground storage tank capacity. This segment includes our crude oil marketing activities.

Onshore crude oil pipelines, terminals and related marketing activities. Our onshore crude oil pipeline systems gather and transport crude oil primarily in Oklahoma, New Mexico and Texas to refineries, centralized storage terminals and connecting pipelines. Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of crude oil transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our consolidated financial statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC.

We own crude oil terminal facilities in Cushing, Oklahoma and Midland, Texas that are used to store crude oil volumes for us and our customers. Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. The customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. In addition, we charge our customers throughput (or “pumpover”) fees based on volumes withdrawn from our terminals. Lastly, we provide fee-based trade documentation services whereby we document the transfer of title for crude oil volumes transacted between buyers and sellers at our terminals. In general, the profitability of our crude oil terminaling operations is dependent upon the level of storage capacity reserved by our customers, the volume of product withdrawn from our terminals and the level of fees charged (including those charged internally, which are eliminated in the preparation of our consolidated financial statements).

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers or on the open market. In general, the sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location. To limit the exposure of our crude oil marketing activities to commodity price risk, our purchases and sales of crude oil are generally contracted to occur within the same calendar month. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing business.

Seasonality. Our onshore crude oil pipelines and related activities typically exhibit little to no effects of seasonality. However, our onshore pipelines situated along the Texas Gulf Coast may be affected by weather events such as hurricanes and tropical storms.

Competition. Within their respective market areas, our onshore crude oil pipelines, terminals and related marketing activities compete with other crude oil pipeline companies, major integrated oil companies and their marketing affiliates, financial institutions with trading platforms and independent crude oil gathering and marketing companies. The onshore crude oil business can be characterized by thin operating margins and strong competition for supplies of crude oil. Declines in domestic crude oil production have intensified this competition. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Properties. The following table summarizes the significant crude oil pipelines and related terminal assets included in our Onshore Crude Oil Pipelines & Services business segment at February 1, 2010.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls) (1)
Crude oil pipelines:				
Seaway Crude Pipeline System	Texas, Oklahoma	50% (2)	530	3.4
Red River System	Texas, Oklahoma	100%	1,690	1.2
South Texas System	Texas	100%	1,150	1.1
West Texas System	Texas, New Mexico	100%	360	0.4
Other (4 systems) (3)	Texas, Oklahoma, New Mexico	Various	681	0.3
Total miles			4,411	
Crude oil terminals:				
Cushing terminal	Oklahoma	100%		3.1
Midland terminal	Texas	100%		1.0
Total capacity				10.5

(1) Useable storage capacity is presented net to our ownership interest in each asset.
(2) Our ownership interest in this pipeline system is held indirectly through our equity method investment in Seaway Crude Pipeline Company (“Seaway”).
(3) Includes our Azelea, Mesquite and Sharon Ridge crude oil gathering systems and Basin Pipeline System. We own 100% of these assets with the exception of the Basin Pipeline System, in which we own a 13% undivided interest.

The maximum number of barrels that our crude oil pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon product composition and demand levels at various delivery points, the exact capacities of our crude oil pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 680 MBPD, 696 MBPD and 652 MBPD during the years ended December 31, 2009, 2008 and 2007, respectively.

The following information highlights the general use of each of our principal crude oil pipelines and terminals, all of which we operate with the exception of the Basin Pipeline System.

§ The *Seaway Crude Pipeline System* is a regulated system that transports imported crude oil from Freeport, Texas to Cushing, Oklahoma and supplies refineries in the Houston, Texas area through its terminal facility at Texas City, Texas. The Seaway Crude Pipeline System also has a connection to our South Texas System that allows it to receive both onshore and offshore domestic crude oil production from the Texas Gulf Coast area for delivery to Cushing.

§ The *Red River System* is a regulated pipeline that transports crude oil from north Texas to south Oklahoma for delivery to either two local refineries or pipeline interconnects for further transportation to Cushing, Oklahoma.

§ The *South Texas System* transports crude oil from an origination point in south Texas to the Houston, Texas area. Crude oil transported on the South Texas System is delivered either to Houston area refineries or pipeline interconnects (including those with our Seaway Crude Pipeline System) for ultimate delivery to Cushing, Oklahoma.

§ The *West Texas System* connects crude oil gathering systems in west Texas and southeast New Mexico to our terminal facility in Midland, Texas.

§ The *Cushing* and *Midland terminals* provide crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has 19 above-ground storage tanks with aggregate crude oil storage capacity of 3.1 MMBbls. The Midland terminal has a storage capacity of 1.0 MMBbls through the use of 12 above-ground storage tanks.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment serves some of the most active drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. This segment includes approximately 1,400 miles of offshore natural gas pipelines, approximately 1,000 miles of offshore crude oil pipelines and six offshore hub platforms.

Our offshore Gulf of Mexico pipelines provide for the gathering and transportation of natural gas or crude oil. In general, revenues from our offshore pipelines are derived from fee-based agreements whereby the customer is charged a fee per unit of volume gathered or transported (typically per MMBtu of natural gas or per barrel of crude oil) multiplied by the volume delivered. These agreements tend to be long-term, often involving life-of-reserve commitments with both firm and interruptible components. In the case of our Poseidon Oil Pipeline System, we purchase crude oil from producers and shippers at a receipt point (at a fixed or index-based price less a location differential) and then sell like quantities of crude oil back to the customer at onshore Louisiana locations (at the same fixed or index-based price, as applicable). The net revenue we recognize from such arrangements is based on the location differential, which represents the fee Poseidon charges for providing transportation services.

Our offshore platforms are integral components of our pipeline operations. In general, platforms are critical components of the energy-related infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore crude oil and natural gas reserves. Platforms are used to: interconnect the offshore pipeline grid; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; conduct drilling operations during the initial development phase of an oil and natural gas property and process off-lease production. Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. For example, the producers utilizing our Independence Hub platform have agreed to pay us $54.6 million of demand fees annually through March 2012. These demand fees are in addition to commodity charges they pay us based on volumes delivered to the platform.

In August 2008, we and Oiltanking Holding Americas, Inc. (“Oiltanking”) announced the formation of a joint venture, the Texas Offshore Port System (“TOPS”), that would design, construct, operate and own a Texas offshore crude oil port and related onshore pipeline and storage system located along the upper Texas Gulf Coast. In April 2009, we dissociated from TOPS. As a result, operating costs and expenses for 2009 includes a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment in TOPS through the date of dissociation. Furthermore, in September 2009, we and Oiltanking entered into a settlement agreement that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized an additional $66.9 million of operating costs and expenses during 2009 in connection with this settlement. The aggregate $135.3 million of charges recorded during 2009 were classified within the Offshore Pipelines & Services business segment.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico. See Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding weather-related risks and insurance matters.

Competition. Within their respective market areas, our offshore pipelines compete with other offshore pipelines primarily on the basis of fees charged, available throughput capacity, connections to downstream markets and proximity and access to existing reserves. Our competitors may have access to greater capital resources than we do, which could enable them to address business opportunities in the Gulf of Mexico more quickly than we can.

Properties. The following table summarizes the significant assets included in our Offshore Pipelines & Services business segment at February 1, 2010.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines:					
High Island Offshore System (1)	100%	291		1,800	
Viosca Knoll Gathering System	100%	137		1,000	
Independence Trail	100%	134		1,000	
Green Canyon Laterals	Various (2)	78		605	
Phoenix Gathering System	100%	77		450	
Falcon Natural Gas Pipeline	100%	14		400	
Anaconda Gathering System	100%	137		300	
Manta Ray Offshore Gathering System (3)	25.7%	250		206	
Nautilus System (3)	25.7%	101		154	
Nemo Gathering System (5)	33.9%	24		102	
VESCO Gathering System (4)	13.1%	158		65	
Total miles		1,401			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline (6)	50%	374			250
Poseidon Oil Pipeline System (7)	36%	367			144
Shenzi Oil Pipeline	100%	83			230
Allegheny Oil Pipeline	100%	43			140
Marco Polo Oil Pipeline	100%	37			120
Constitution Oil Pipeline	100%	67			80
Typhoon Oil Pipeline	100%	17			80
Tarantula Oil Pipeline	100%	4			30
Total miles		992			
Offshore hub platforms:					
Independence Hub	80%		8,000	800	N/A
Marco Polo (8)	50%		4,300	150	60
Viosca Knoll 817	100%		671	145	5
Garden Banks 72	50%		518	113	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) Based on the maximum allowable operating pressure, our HIOS pipeline system can transport up to 1,800 MMcf/d of natural gas. On January 12, 2010, we filed for FERC authority to reduce the firm certificated capacity on the HIOS pipeline system from 1,400 MMcf/d to 350 MMcf/d.
(2) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100%.
(3) Our ownership interest in these pipeline systems is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").
(4) Our ownership interest in this system is held indirectly through our equity method investment in VESCO.
(5) Our ownership interest in this system is held indirectly through our equity method investment in Nemo Gathering Company, LLC ("Nemo").
(6) Our 50% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(7) Our ownership interest in this system is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC. ("Poseidon").
(8) Our 50% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").

We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 22.3%, 22% and 24.1% during the years ended December 31, 2009, 2008 and 2007, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

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

- § The *High Island Offshore System* ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. In addition, this system includes the 86-mile East Breaks System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

- § The *Viosca Knoll Gathering System* transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

- § The *Independence Trail* natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline platform at West Delta 68. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

- § The *Green Canyon Laterals* consist of 13 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including HIOS.

- § The *Phoenix Gathering System* connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

- § The *Falcon Natural Gas Pipeline* delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located at the Brazos Addition Block 133 platform.

- § The *Anaconda Gathering System* connects our Marco Polo platform and the third-party owned Constitution platform to the ANR pipeline system.

- § The *Manta Ray Offshore Gathering System* transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System.

- § The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant located in south Louisiana.

- § The *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

- § The *VESCO Gathering System* is a regulated natural gas pipeline system associated with the Venice natural gas processing plant in south Louisiana. This gathering pipeline is an integral part of the natural gas processing operations of VESCO and is accounted for under our NGL Pipelines & Services business segment.

The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 28.7%, 20.1% and 19.3% during the years ended December 31, 2009, 2008 and 2007, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

- § The *Cameron Highway Oil Pipeline* gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This system includes one pipeline junction platform.

- § The *Poseidon Oil Pipeline System* gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform.

- § The *Shenzi Oil Pipeline* provides gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi Oil Pipeline allows producers to access our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- § The *Allegheny Oil Pipeline* connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- § The *Marco Polo Oil Pipeline* transports crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

- § The *Constitution Oil Pipeline* serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

With respect to natural gas processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 39.4%, 36.5% and 28.6% during the years ended December 31, 2009, 2008 and 2007, respectively. With respect to crude oil processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 13.6%, 16.9% and 26.1% during the years ended December 31, 2009, 2008 and 2007, respectively. For recently constructed assets, these rates reflect the periods since the dates such assets were placed into service. In addition to our offshore hub platforms, we also own or have an ownership interest in 13 pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

The following information highlights the general use of each of our principal Gulf of Mexico offshore hub platforms. We operate these platforms with the exception of the Independence Hub and Marco Polo platforms.

- § The *Independence Hub* platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from deepwater production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

- § The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located in the South Green Canyon area of the Gulf of Mexico.

- § The *Viosca Knoll 817* platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.

- § The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- § The *East Cameron 373* platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.

§ The *Falcon Nest* platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, processes natural gas from the Falcon field.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services business segment consists of (i) propylene fractionation plants and related activities, (ii) butane isomerization facilities, (iii) an octane enhancement facility, (iv) refined products pipelines, including our Products Pipeline System (as defined below), and related activities and (v) marine transportation and other services.

Propylene fractionation and related activities. Our propylene fractionation and related activities primarily consist of two propylene fractionation plants (one located in Mont Belvieu, Texas and the other in Baton Rouge, Louisiana), propylene pipeline systems aggregating approximately 670 miles in length and related petrochemical marketing activities. This business includes an export facility and associated above-ground polymer grade propylene storage spheres located in Seabrook, Texas.

In general, propylene fractionation plants separate refinery grade propylene, which is a mixture of propane and propylene, into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade and chemical grade propylene can also be produced as a by-product of ethylene production. The demand for polymer grade propylene primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery and molded plastic parts for appliances and automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. The toll processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation. Our petrochemical marketing activities generate revenues from the purchase and fractionation of refinery grade propylene in the open market and the sale and delivery of products obtained through our propylene fractionation activities. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for such factors as delivery location. The majority of revenues from our propylene pipelines are based upon a transportation fee per unit of volume multiplied by the volume delivered to the customer.

As part of our petrochemical marketing activities, we have several long-term refinery grade purchase and polymer grade propylene sales agreements. To limit the exposure of our petrochemical marketing activities to commodity price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Butane isomerization. Our butane isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization facility in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane, high-purity isobutane and residual normal butane. The primary uses of isobutane are for the production of propylene oxide, isooctane and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry’s requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of isomerization. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility.

Octane enhancement. We own and operate an octane enhancement production facility located in Mont Belvieu, Texas that is designed to produce isooctane, isobutylene and methyl tertiary butyl ether ("MTBE"). These products are used in reformulated motor gasoline blends to increase octane values. The high-purity isobutane feedstocks consumed in the production of these products are supplied by our isomerization units. To the extent that MTBE is produced at the facility, it is sold into the export market. The results of operations of this business are generally dependent upon the sale and delivery of products produced. In general, we sell our octane enhancement products at market-based prices, which may include pricing differentials for such factors as delivery location. We attempt to mitigate price risk by entering into certain commodity hedging transactions. This facility undergoes an annual maintenance turnaround that generally occurs during the first quarter of each year. During these periods of shutdown, the plant may incur operating losses.

Refined products pipelines and related activities. Our refined products pipelines and related activities primarily consist of (i) a regulated 4,700-mile products pipeline system and related terminal operations (the "Products Pipeline System") that generally extends in a northeasterly direction from the upper Texas Gulf Coast to the northeast United States and (ii) a 50% joint venture interest in Centennial Pipeline LLC ("Centennial"), which owns a 794-mile refined products pipeline system that extends from the upper Texas Gulf Coast to central Illinois (the "Centennial Pipeline").

The Products Pipeline System transports refined products, and to a lesser extent, petrochemicals such as ethylene and propylene and NGLs such as propane and normal butane. These refined products are produced by refineries and include gasoline, diesel fuel, aviation fuel, kerosene, distillates and heating oil. Refined products also include blend stocks such as raffinate and naphtha. Blend stocks are primarily used to produce gasoline or as a feedstock for certain petrochemicals. The Centennial Pipeline intersects our Products Pipeline System near Creal Springs, Illinois, and effectively loops the Products Pipeline System between Beaumont, Texas and south Illinois. Looping the Products Pipeline System permits effective supply of products to points south of Illinois as well as incremental product supply capacity to other Midcontinent markets.

Our refined products pipelines and related activities include the distribution and marketing operations we provide at our Aberdeen, Mississippi and Boligee, Alabama river terminals. In the fourth quarter of 2009, we expanded the terminaling and marketing operations associated with our refined products pipeline business. These activities generated nominal amounts of gross operating margin during 2009; however, we expect that our refined products marketing activities will increase beginning in 2010 in an effort to increase the utilization of our portfolio of refined products pipelines and terminal assets.

The results of operations of our refined products pipelines are primarily dependent on the tariffs charged to customers to transport products. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. Our related marketing activities generate revenues from the sale and delivery of refined products obtained from third parties on the open market. In general, we sell our refined products at market-based prices, which may include pricing differentials for such factors as delivery location.

Marine transportation and other services. Our marine transportation business consists of tow boats and tank barges that are used primarily to transport refined products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products along key inland and intercoastal U.S. waterways. Our marine transportation assets service refinery and storage terminal customers along the Mississippi, Illinois and Ohio rivers, the Intracoastal Waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. In addition, we provide marine vessel fueling services for cruise liners and cargo ships as well as other ship-assist services in Miami, Florida. Other non-marine services consist of the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels by truck, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region of the United States.

The results of operations of our marine transportation business, which we entered into in February 2008 upon the acquisition of tow boats, tank barges and related assets from Cenac Towing Co., Inc. and affiliates (collectively, "Cenac"), are generally dependent upon the level of fees charged to transport cargo. Transportation services are typically 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.

The results of operations from the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels are dependent on the sales price or transportation fees that we charge our customers.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher levels of demand in the spring and summer months due to increased demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, octane additive prices have been stronger during the April to September period of each year, which corresponds with the summer driving season, when motor gasoline demand increases.

Our refined products pipelines and related activities exhibit seasonality based upon the mix of products delivered and the weather and economic conditions in the geographic areas being served. Refined products volumes are generally higher during the second and third quarters of each year because of greater demand for motor gasoline during the spring and summer driving seasons. NGL transportation volumes on the Products Pipeline System are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending in motor gasoline).

Our marine transportation business exhibits some seasonal variation. Demand for motor gasoline and asphalt is generally stronger in the spring and summer months due to the summer driving season and when weather allows for more efficient road construction. Weather events, such as hurricanes and tropical storms in the Gulf of Mexico, can adversely impact both the offshore and inland businesses. Generally during the winter months, cold weather and ice can negatively impact the inland operations on the upper Mississippi and Illinois rivers.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, our propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, quality of customer service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage supporting infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

The Products Pipeline System's most significant competitors are third-party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, quality of customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the areas served by our Products Pipeline System and river terminals. The Products Pipeline System faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

Our marine transportation business competes with other 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. Competition within the marine transportation business is largely based on price.

Properties. The following table summarizes the significant propylene fractionation, isomerization and octane enhancement production facilities and petrochemical pipelines included in our Petrochemical & Refined Products Services business segment at February 1, 2010, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various (1)	73	87	
BRPC	Louisiana	30% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100% (4)			284
North Dean Pipeline System	Texas	100%			138
Texas City RGP Gathering System	Texas	100%			86
Others (6 systems) (5)	Texas, Louisiana	Various (6)			230
Total miles					738
Octane enhancement production facilities:					
Mont Belvieu (7)	Texas	100%	12	12	

(1) We own a 66.7% interest in three of the units, which have an aggregate 41 MBPD of total plant capacity. In October 2009, we acquired the remaining 45.4% of one unit having 17 MBPD of plant capacity. We own 100% of the remaining two units.
(2) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").
(3) On a weighted-average basis, utilization rates for this facility were approximately 83.6%, 74.1% and 77.6% during the years ended December 31, 2009, 2008 and 2007, respectively.
(4) Reflects consolidated ownership of these pipelines by EPO (34%) and Duncan Energy Partners (66%).
(5) Includes our Texas City PGP Delivery System and Port Neches, La Porte, Port Arthur, Lake Charles and Bayport petrochemical pipelines.
(6) We own 100% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C. In addition, we own a 50% undivided interest in the Lake Charles pipeline.
(7) On a weighted-average basis, utilization rates for this facility were approximately 50%, 58.3% and 58.3% during the years ended December 31, 2009, 2008 and 2007, respectively.

We produce polymer grade propylene at our Mont Belvieu, Texas propylene fractionation facility and chemical grade propylene at our BRPC facility located in Baton Rouge, Louisiana. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of Exxon Mobil Corporation into chemical grade propylene. The polymer grade propylene produced by our Mont Belvieu facility is primarily for the benefit of our tolling customers and used in our petrochemical marketing activities to service long-term third-party supply contracts. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 85%, 72.2% and 86% during the years ended December 31, 2009, 2008 and 2007, respectively. As noted previously, this business includes an export facility and above-ground polymer grade propylene storage spheres. This facility, which is located on the Houston Ship Channel in Seabrook, Texas, can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex Propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a third-party pipeline interconnect located in Cameron Parish, Louisiana. The North Dean Pipeline System transports refinery grade propylene from Mont Belvieu, Texas, to Point Comfort, Texas.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 124 MBPD, 116 MBPD and 114 MBPD during the years ended December 31, 2009, 2008 and 2007, respectively.

The following table summarizes the significant refined products pipelines and related terminal and storage assets included in our Petrochemical & Refined Products Services business segment at February 1, 2010.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
Refined products pipelines and terminals:				
Products Pipeline System (1)	Texas to Midwest and Northeast U.S.	100%	4,700	13.0
Centennial Pipeline	Texas to central Illinois	50% (2)	794	2.3
Other pipelines (3)	Texas	100%	210	--
River terminals (4)	Alabama, Mississippi	100%	n/a	0.6
Total			5,704	15.9

(1) In addition to the 13 MMBbls of refined products working storage capacity, we have 5.4 MMBbls of NGL working storage capacity that is used to support operations on our Products Pipeline System. Our NGL storage and terminal assets are accounted for under our NGL Pipelines & Services business segment.
(2) Our ownership interest in this pipeline is held indirectly through our equity method investment in Centennial.
(3) Our Products Pipeline System includes 210 miles of unregulated pipelines in south Texas used primarily to transport petrochemical products.
(4) Represents product distribution and marketing terminals located in Aberdeen, Mississippi and Boligee, Alabama.

The maximum number of barrels that our refined products pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our liquids pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for the Products Pipeline System were as follows for the periods presented:

	For Year Ended December 31,		
	2009	2008	2007
Refined products transportation (MBPD)	459	492	542
Petrochemical transportation (MBPD)	118	104	111
NGLs transportation (MBPD)	105	106	115

The following information highlights the general use of each of our principal refined products pipelines and related assets.

§ The *Products Pipeline System* is a regulated pipeline system that transports refined products, petrochemicals and NGLs. This pipeline system includes receiving, storage and terminaling facilities and is present in 12 states: Texas, Louisiana, Arkansas, Tennessee, Missouri, Illinois, Kentucky, Indiana, Ohio, West Virginia, Pennsylvania and New York. 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, Indiana, Ohio and Kentucky. At these points, refined products are delivered to terminals owned by us, connecting pipelines and customer-owned terminals. Petrochemicals are transported on our Products Pipeline System between Mont Belvieu, Texas and Port Arthur, Texas. Our Products Pipeline System transports NGLs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States and is the only pipeline that transports NGLs from the upper Texas Gulf Coast to the Northeast. The Centennial Pipeline effectively loops our Products Pipeline System between Beaumont, Texas and southern Illinois.

In December 2006, we signed an agreement with Motiva Enterprises, LLC ("Motiva") to construct and operate a refined products storage facility to support an expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we will construct 20 storage tanks with a capacity of 5.4 MMBbls for gasoline and distillates, five 5-mile product pipelines connecting the storage facility to Motiva's refinery and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. As part of a separate but complementary initiative, we constructed an 11-mile pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas.

§ *Centennial Pipeline* is a regulated refined products pipeline system that extends from Texas to Illinois. The Centennial Pipeline extends from an origination facility located on our Products Pipeline System in Beaumont, Texas, to Bourbon, Illinois. Centennial owns a 2.3 MMBbl refined products storage terminal located near Creal Springs, Illinois.

During 2009, we recognized a non-cash asset impairment charge of $17.6 million in connection with a reduction in future forecasted levels of throughput volumes at the Aberdeen and Boligee river terminals resulting from the suspension of three associated proposed river terminal construction projects. In addition, we accrued a liability of $28.7 million for pipeline deficiency fees we expect to pay a third-party in the future as a result of the reduced throughput volume forecast. For information regarding the asset impairment charge, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following table summarizes the significant marine transportation assets included in our Petrochemical & Refined Products Services business segment at February 1, 2010.

Class of Equipment	Number in Class	Capacity (bbl)/ Horsepower (hp) (as indicated by sign)
Inland marine transportation assets:		
Barges	32	< 25,000 bbl
Barges	96	> 25,000 bbl
Tow boats	32	< 2,000 hp
Tow boats	30	=/> 2,000 hp
Offshore marine transportation assets:		
Barges (includes three single-bottom barges)	8	> 20,000 bbl
Tow boats	4	< 2,000 hp
Tow boats	3	> 2,000 hp

Our fleet of marine vessels operated at an average utilization rate of 87% and 93% during 2009 and 2008, respectively. These utilization rates reflect the period since we acquired these marine transportation assets.

The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. We refer to the combination of the power source and freight capacity as a tow. Our inland tows generally consist of one tow boat paired with up to four tank barges, depending upon the horsepower of the tow boat, location, waterway conditions, customer requirements and prudent operational considerations. Our offshore tows generally consist of one tow boat and one ocean-certified tank barge. In June 2009, we expanded our marine transportation business with the acquisition of 19 tow boats and 28 tank barges from TransMontaigne Product Services Inc. for $50.0 million in cash. Our marine transportation business is subject to regulation by the U.S. Department of Transportation ("DOT"), Department of Homeland Security, Commerce Department and the U.S. Coast Guard ("USCG") and federal and state laws.

Other Investments

This segment reflects the Parent Company's non-controlling ownership interests in Energy Transfer Equity and its general partner, LE GP, both of which are accounted for using the equity method. In May 2007, the Parent Company paid $1.65 billion to acquire approximately 17.6% of the common units of Energy Transfer Equity, or 38,976,090 units, and approximately 34.9% of the membership interests of LE GP. On January 22, 2009, the Parent Company acquired an additional 5.7% membership interest in LE GP for $0.8 million, which increased our total ownership in LE GP to 40.6%.

LE GP. The business purpose of LE GP is to manage the affairs and operations of Energy Transfer Equity. LE GP has no separate business activities outside of those conducted by Energy Transfer Equity. The commercial management of Energy Transfer Equity does not overlap with that of Enterprise Products Partners. LE GP owns a 0.31% general partner interest in Energy Transfer Equity and has no IDRs in the quarterly cash distributions received from Energy Transfer Equity.

Energy Transfer Equity. Energy Transfer Equity has no separate operating activities apart from those of ETP. As of December 31, 2009, Energy Transfer Equity's principal sources of distributable cash flow are its investments in the limited and general partner interests of ETP as follows:

§ Direct ownership of 62,500,797 ETP limited partner units, representing approximately 35% of ETP's total outstanding common units at December 31, 2009.

§ Indirect ownership of the general partner interest of ETP (representing a 1.9% interest as of December 31, 2009) and all associated IDRs held by ETP's general partner, of which Energy Transfer Equity owns 100% of the membership interests. Currently, the quarterly general partner and associated IDR thresholds of ETP's general partner are based on the ETP general partner percentage interest, plus the following with respect to the IDRs:

  § 13% of quarterly cash distributions from $0.275 per unit up to $0.3175 per unit paid by ETP;

  § 23% of quarterly cash distributions from $0.3175 per unit up to $0.4125 per unit paid by ETP; and

  § 48% of quarterly cash distributions that exceed $0.4125 per unit paid by ETP.

ETP's partnership agreement requires that it distribute all of its Available Cash (as defined in such agreement) within 45 days following the end of each fiscal quarter.

ETP is a publicly traded partnership owning and operating a diversified portfolio of midstream energy assets. ETP has pipeline operations in Arizona, Colorado, Louisiana, New Mexico and Utah, and owns the largest intrastate natural gas pipeline system in Texas. ETP's natural gas operations include natural gas gathering and transportation pipelines, natural gas treating and processing assets and three natural gas storage facilities located in Texas. ETP is also one of the three largest retail marketers of propane in the United States, serving more than one million customers across the country.

ETP operates in four business lines: (i) Midstream; (ii) Intrastate Transportation and Storage; (iii) Interstate Transportation and (iv) Retail Propane. The following sections summarize the activities and principal properties of each of these business lines.

Midstream. This business line includes ETP's ownership and operation of approximately 7,000 miles of natural gas gathering pipelines, three natural gas processing plants, 11 natural gas treating facilities and 11 natural gas conditioning facilities. These facilities are located primarily in Texas, Utah and Colorado. The results of operations from this business line are primarily dependent on the level of fees charged in connection with ETP's gathering, transportation and processing of natural gas and processing of NGLs. In addition, ETP generates margins from the marketing of natural gas to utilities, industrial consumers and other marketers and pipeline companies. ETP also utilizes derivative instruments to generate income for this business line. These trading activities are limited in scope and in accordance with ETP's commodity risk management policies.

Intrastate Transportation and Storage. This business line of ETP includes approximately 7,800 miles of natural gas transportation pipelines and three natural gas storage facilities. The results of operations from this business line are primarily dependent on the level of transportation fees charged by ETP and margins from natural gas sales made in connection with ETP's HPL System.

The key assets within this business line are the HPL System and the ET Fuel System. The HPL System consists of approximately 4,300 miles of intrastate natural gas pipeline with an aggregate capacity of 5.5 Bcf/d and the Bammel underground storage reservoir and related transportation assets. The HPL System has access to multiple sources of historically significant natural gas supply reserves from south Texas, the Gulf Coast of Texas, east Texas and the western Gulf of Mexico, and is directly connected to major gas distribution, electric and industrial load centers in Houston, Corpus Christi, Texas City and other cities located along the Gulf Coast of Texas. The ET Fuel System is comprised of approximately 2,570 miles of intrastate natural gas pipelines and related storage facilities located in Texas. The ET Fuel System is located near high-growth production areas and provides ETP access to the Waha Hub near Midland, Texas, Katy Hub near Houston, Texas and Carthage Hub in east Texas.

Interstate Transportation. This business line includes ETP's Transwestern pipeline and a 50% interest in two pipeline joint ventures with Kinder Morgan Energy Partners L.P. ("Kinder Morgan"). The results of operations from ETP's interstate pipelines are dependent on the level of natural gas transportation fees charged and operational gas sales margins.

The Transwestern pipeline is a FERC-regulated interstate natural gas pipeline extending approximately 2,700 miles from the gas producing regions of west Texas, east and northwest New Mexico, and south Colorado primarily to pipeline interconnects off the east end of its system and pipeline interconnects at the California border. The Transwestern pipeline has access to three significant gas supply basins: the Permian Basin in west Texas and east New Mexico; the San Juan Basin in northwest New Mexico and south Colorado and the Anadarko Basin in the Texas and Oklahoma panhandles. Natural gas sources from the San Juan Basin and surrounding producing areas can be delivered eastward to Texas intrastate and mid-continent connecting pipelines and natural gas market hubs as well as westward to markets in Arizona, Nevada and California. Transwestern's customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.

This business line also includes ETP's joint development with Kinder Morgan of the approximately 500-mile interstate natural gas pipeline, the Midcontinent Express pipeline, which commenced service in 2009. This new pipeline originates near Bennington, Oklahoma, is routed through Perryville, Louisiana, and terminates at an interconnect with Transco's interstate natural gas pipeline in Butler, Alabama. The Transco pipeline delivers natural gas to significant markets in the northeast portion of the United States.

In October 2008, ETP entered into a 50/50 joint venture with Kinder Morgan for the development of the Fayetteville Express pipeline, an approximately 187-mile, 42-inch pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. The pipeline is expected to have an initial capacity of 2.0 Bcf/d and is expected to be in service by early 2011. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d.

In January 2009, ETP announced that it had entered into an agreement to construct the Tiger pipeline, a 178-mile 42-inch interstate natural gas pipeline. The Tiger pipeline will connect to ETP's dual 42-inch pipeline system near Carthage, Texas extend through the heart of the Haynesville Shale and end near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana. The Tiger pipeline will have an initial throughput capacity of 2.0 Bcf/d, which may be increased to 2.4 Bcf/d with added compression. ETP has secured binding long-term commitments for transportation of 2.0 Bcf/d. The Tiger pipeline is expected to be in service in early 2011.

ETP's midstream, intrastate transportation and storage and interstate transportation businesses experience little to no effects from seasonality. ETP competes with other natural gas and NGL pipelines on the basis of location, capacity, price and reliability. ETP's competitors include major integrated oil companies, interstate and intrastate pipelines and other companies that gather, compress, treat, process, transport and market natural gas. In marketing natural gas, ETP has numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience.

Retail Propane. ETP, through its subsidiaries Heritage Operating, L.P. and Titan Energy Partners, L.P., is one of the three largest retail propane marketers in the United States based on gallons sold. ETP serves more than one million customers from approximately 440 customer service locations in approximately 40 states. ETP's propane operations extend from coast-to-coast with concentrations in the western, upper midwestern, northeastern and southeastern regions of the United States. ETP's propane business has grown primarily through acquisitions of retail propane operations and, to a lesser extent, through internal growth.

Retail propane is a margin-based business in which gross profits depend on the excess of sales price over propane supply cost. The market price of propane is often subject to volatile changes as a result of supply or other market conditions over which ETP has no control. Historically, ETP has generally been successful in maintaining retail gross margins on an annual basis despite changes in the wholesale cost of propane; however, there is no assurance that ETP will always be able to fully pass on product cost increases, particularly when product costs rise rapidly. Consequently, the profitability of ETP's retail propane business is sensitive to changes in wholesale propane prices.

ETP's propane business is seasonal and dependent upon weather conditions in its market areas. Historically, approximately two-thirds of ETP's retail propane volume and substantially all of its propane-related operating income, is attributable to sales during the six-month peak-heating season of October through March. This pattern generally results in higher operating revenues and net income for ETP's retail propane business line during the period October through March of each year, and lower revenues and either net losses or lower net income during the period from April through September of each year. ETP's cash flow from operations is generally greatest when customers pay for propane purchased during the six-month peak heating season. Sales to commercial and industrial customers are much less sensitive to changes in the weather.

Propane competes with other sources of energy, some of which are less costly for equivalent energy value. ETP competes for customers against suppliers of electricity, natural gas and fuel oil. Competition from alternative energy sources has been increasing as a result of reduced utility regulation. ETP also competes with other companies engaged in the retail propane distribution business. Competition in the propane industry is highly fragmented and generally occurs on a local basis with other large multi-state propane marketers, thousands of smaller local independent marketers and farm cooperatives. The ability to compete effectively further depends on the reliability of service, responsiveness to customers and the ability to maintain competitive prices.

Title to Properties

Enterprise Products Partners' real property holdings fall into two basic categories: (i) parcels that it and its unconsolidated affiliates own in fee (e.g., Enterprise Products Partners owns the land upon which its Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which Enterprise Products Partners' interests and those of its affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for Enterprise Products Partners' operations. The fee sites upon which Enterprise Products Partners' significant facilities are located have been owned by them or their predecessors in title for many years without any material challenge known to Enterprise Products Partners relating to title to the land upon which the assets are located, and Enterprise Products Partners believes that it has satisfactory title to such fee sites. Enterprise Products Partners and its affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by Enterprise Products Partners or to its rights pursuant to any material lease, easement, right-of-way, permit or license, and Enterprise Products Partners believes that it has satisfactory rights pursuant to all of its material leases, easements, rights-of-way, permits and licenses.

Capital Spending

For a discussion of our capital spending programs, see "Liquidity and Capital Resources" included under Item 7 of this annual report.

Regulation

Interstate Pipelines

Liquids Pipelines. Certain of our refined products, crude oil and NGL pipeline systems (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates 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 together with interest 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 related 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., deems "grandfathered") liquids pipeline rates that (i) were in effect for the 12 months preceding enactment and (ii) that had not been subject to complaint, protest or investigation. Some, but not all, of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year-to-year in the Producer Price Index for finished goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's costs. Effective March 21, 2006, the 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%. Prior to the end of that five year period, the FERC will once again review the PPI to determine whether it continues to measure adequately the cost changes in the liquids pipeline industry.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements with all of the pipeline's shippers that the rate is acceptable. Our Products Pipeline System 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, and the Arcadia destination within the Shreveport-Arcadia, Louisiana destination markets, which are currently subject to the PPI.

Due to the complexity of ratemaking, the lawfulness of any rate is never assured. Prescribed rate methodologies for approving regulated tariff rates may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC's methodology for approving rates could adversely affect us. In addition, challenges to our tariff rates could be filed with the FERC and decisions by the FERC in approving our regulated rates could adversely affect our cash flow. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

Mid-America Pipeline Company, LLC ("Mid-America") and Seminole are currently involved in a rate case before the FERC. The case primarily involves shipper protests of rate increases on Mid-America's Northern System in FERC Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000, and challenges to Seminole's interstate rates and certain joint rates between Seminole and Mid-America's Rocky Mountain System in FERC Docket Nos. OR06-5-000 and IS06-520-000. A hearing before an Administrative Law Judge began on October 2, 2007 and culminated with an initial decision on September 3, 2008. On October 23, 2009, the FERC approved an uncontested settlement agreement between Mid-America and the primary parties protesting the Northern System rates, which resolved all matters involving Mid-America's Northern System at issue in Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000. Pursuant to the settlement agreement, Mid-America filed new rates for certain propane movements on the Northern System, which took effect January 1, 2010. Mid-America has also paid refunds to propane shippers, as provided by the settlement agreement.

The settlement agreement did not cover the challenges to the Seminole and Mid-America Rocky Mountain System rates at issue in Docket Nos. OR06-5-000 and IS06-520-000. On February 18, 2010, the FERC ruled on those issues, affirming the Initial Decision in all respects. The FERC's order also clarified that Mid-America's capacity allocation provisions were not subject to challenge in the case but that the changes to Mid-America's rates contained in FERC Tariff No. 45 were properly at issue. The FERC required Seminole and Mid-America to file revised rates in compliance with its order by March 22, 2010.

On November 5, 2009, Flint Hills Resources, LP ("Flint Hills") filed a complaint against Mid-America at the FERC in Docket No. OR10-2-000. The Flint Hills complaint challenges the rates for certain movements of butane, isobutane, natural gasoline, naphtha and refinery grade butane on Mid-America's Northern System. On February 2, 2010, the FERC issued an order establishing hearing procedures but holding them in abeyance subject to settlement discussions. We are unable to predict the outcome of this litigation.

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

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

Natural Gas Pipelines. Our interstate natural gas pipelines and storage facilities that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 ("NGA"). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth rates and terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC if it finds, on its own initiative or as a result of challenges to the rates by third parties, that they are unjust, unreasonable or otherwise unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived and charged based on a cost-of-service methodology.

The FERC's authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also includes: (i) certification, construction, and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services and (v) various other matters. The FERC's rules require interstate pipelines and their affiliates to adhere to Standards of

Conduct that, among other things, require that transportation employees function independently of marketing employees. The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to that act, the FERC established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1.0 million per day per violation.

In March 2009, we submitted to the FERC a general rate change application under Section 4 of the NGA proposing, among other things, an increase in the firm and interruptible transportation rates for High Island Offshore System, LLC. On April 23, 2009, the FERC issued an order accepting the rates subject to refund, conditions and the outcome of an evidentiary hearing. The rates went into effect subject to refund in October 2009. In February 2010, the FERC's Staff and the active intervenors reached an agreement in principle that, if filed as a formal settlement and approved by the FERC, will resolve all outstanding issues in the proceeding. Pending the FERC's action on the proposed settlement, the hearing procedures will be held in abeyance.

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

Intrastate Pipelines

Liquids Pipelines. Certain of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary widely, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may challenge our intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma and Texas.

Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Certain of our intrastate natural gas pipelines are also subject to limited regulation by the FERC under the NGPA because they provide transportation and storage service pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline may transport gas on behalf of an interstate pipeline company or any local distribution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the NGA. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, and to make certain rate and other filings and reports in compliance with the FERC's regulations. The rates for Section 311 services may be established by the FERC or the respective state agency, but such rates may not exceed a fair and equitable rate.

In September 2007, the FERC approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Texas Pipeline. In June and July 2008, we filed to amend our Statement of Operating Conditions ("SOC") for our transportation and storage services, respectively. In September 2008, we submitted to the FERC a new proposed Section 311 rate for service on our Sherman Extension pipeline. On November 23, 2009, we filed an uncontested settlement agreement, which, if approved, would resolve the Sherman Extension rate issues. The other issues related to the SOC are reserved under the settlement agreement for a decision by the FERC based on the pleadings. Under the settlement agreement that resulted from the September 2007 proceeding, we are required to file another rate petition on or before April 2010 to justify our current rates or establish new rates for the NGPA Section 311 service on the remainder of the system. The FERC has not acted upon the settlement agreement. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

In September 2007, the FERC also approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Alabama Intrastate Pipeline. We are required to file another rate petition on or before May 2010 to justify our current rates or establish new rates for NGPA Section 311 service. The Alabama Public Service Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Alabama.

In July 2009, we filed with the FERC proposed changes to our SOC and to increase our interruptible transportation rates for NGPA Section 311 service for the Acadian and Cypress pipelines, which are part of our Acadian Gas System. On December 8, 2009, the FERC issued an order extending its review period to encourage settlement discussions. Settlement negotiations are on-going.

Sales of Natural Gas

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to FERC jurisdiction. However, under current federal rules the price at which we sell natural gas is not regulated insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Our affiliates that engage in natural gas marketing are considered marketing affiliates of certain of our interstate natural gas pipelines. The FERC's rules require pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to standards of conduct that, among other things, require that their transportation and marketing employees function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has also established rules prohibiting energy market manipulation. A violation of these rules by us or our employees or agents may subject us to civil penalties, suspension or loss of authorization to perform such sales, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. The Federal Trade Commission and the Commodity Futures Trading Commission also have issued rules and regulations prohibiting market manipulation.

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC has adopted new market monitoring and annual reporting regulations which are applicable to many intrastate pipelines and other entities that are otherwise not subject to the FERC's NGA jurisdiction. The FERC also has established rules requiring certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points, and has also required the annual reporting of gas sales information, in order to increase transparency in natural gas markets. Non-interstate service providers, which include NGPA Section 311 service providers, are required to begin posting the information by June 30, 2010. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Marine Operations

Maritime Law. The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under 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 coastwise maritime transportation between locations in the United States, and as such, we are subject to the provisions of the Jones Act. 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 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 American Bureau of Shipping ("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. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness. 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.

For additional information regarding the potential impact of federal, state or local regulatory measures on our business, please read Item 1A "Risk Factors" of this annual report.

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 ("CERCLA"); the Resource Conservation and Recovery Act ("RCRA"); the Federal Clean Air Act ("CAA"); the Federal Water Pollution Control Act of 1972, renamed and amended as the Clean Water Act ("CWA"); the Oil Pollution Act of 1990 ("OPA"); 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 financial position, results of operations and cash flows. 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 financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, other than certain matters discussed in Note 18 of the Notes to Consolidated Financial Statements under Item 8 of this annual report, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations and cash flows. Environmental and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating 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. Below is a discussion of the material environmental laws and regulations that relate to our business.

Air Emissions

Our operations are subject to the CAA 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 CAA, 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 CAA. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than any other similarly situated company.

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide and methane, are contributing to the warming of the Earth’s atmosphere and other climatic changes, the U.S. Congress has been actively considering legislation to reduce such emissions. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (“ACESA”), which would establish an economy-wide cap-and-trade program intended to reduce U.S. emissions of “greenhouse gases” including carbon dioxide and methane that may contribute to warming of the Earth’s atmosphere and other climatic changes. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the Environmental Protection Agency (“EPA”) would issue a capped and steadily declining number of tradable emissions allowances to major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The costs of these allowances would be expected to escalate significantly over time. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services.

In addition, on December 7, 2009, the EPA announced its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its endangerment finding that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil, natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services.

The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final regulations.

Even if such legislation is not adopted at the national level, more than one-third of the states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to greenhouse gas emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial position and results of operations.

Other Potential Impacts of Climate Change

Over the last hundred years or so, certain instrumental temperature records have evidenced a general increase in global mean temperature. As a result, certain public advocacy groups attribute this rise to a phenomenon termed “global warming.” Proponents of this theory argue that man-made greenhouse gases have produced observable changes in the environment such as shrinkage of the Arctic ice caps, releases of terrestrial carbon from permafrost regions and increases in sea level. In addition, these individuals believe that global warming will result in a continued increase in global average temperatures over the course of this century, with a probable increase in the frequency of extreme weather events, and changes in rainfall patterns. Based on computer models promoted by these groups, certain areas of the globe might benefit from such changes, while other areas would experience costs. Severe global climate change could even result in reduced diversity of ecosystems and the extinction of certain species.

There is considerable debate in public and private forums as to whether global warming is actually occurring and, if it is, its consequences. However, if global warming is occurring, it could have an impact on our operations. For example, our facilities that are located in low lying areas such as the coastal regions of Louisiana may be at increased risk due to flooding or more frequent and severe weather events. Also, a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases may reduce volumes available to us for processing, transportation, marketing and storage. Unfortunately, there is currently no public consensus regarding global warming, and the scientific community is divided on the subject. We are providing this disclosure regarding the potential physical effects of global warming based on publicly available information and opinions on the matter. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming.

Water

The CWA and comparable state laws impose strict controls on 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 EPA has also 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 further 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 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 there is no assurance that the effect will not be material in the aggregate.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal 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. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future, we may be required to remove or remediate these materials.

Environmental Remediation

The 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.

Pipeline Safety Matters

We are subject to regulation by the 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 (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Secretary of Transportation. We believe we are in material compliance with these HLPSA regulations.

We are also 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. In addition, we are subject to the DOT regulation that requires pipeline operators to institute certain control room procedures. These procedures must be developed by August 1, 2011 and implemented by February 2, 2012. We believe we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program 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 that 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, the 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." We have identified our HCA pipeline segments and developed an appropriate Integrity Management Program.

Risk Management Plans

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

Safety Matters

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

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

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

Employees

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. For additional information regarding the ASA, see "EPCO ASA" in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. As of December 31, 2009, there were approximately 4,800 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 3,300 of these individuals devote all of their time performing administrative, commercial and operating duties for us. The remaining approximate 1,500 personnel are part of EPCO's shared service organization and spend a portion of their time engaged in our business.

Available Information

As a publicly traded partnership, we electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC, including us.

We provide electronic access to our periodic and current reports on our Internet website, www.enterprisegp.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 (866) 230-0745 for paper copies of these reports free of charge. We do not intend to incorporate the information on our website into this document.

Additionally, Enterprise Products Partners, Duncan Energy Partners, Energy Transfer Equity and ETP electronically file certain documents with the SEC, including annual reports on Form 10-K and quarterly reports on Form 10-Q. These entities also provide electronic access to their respective periodic and current reports on their Internet websites. The SEC file number for each registrant and company website address is as follows:

- Enterprise Products Partners – SEC File No. 1-14323; website address: www.epplp.com
- Duncan Energy Partners – SEC File No. 1-33266; website address: www.deplp.com
- Energy Transfer Equity – SEC File No. 1-32740; website address: www.energytransfer.com
- ETP – SEC File No. 1-11727; website address: www.energytransfer.com

Item 1A. *Risk Factors*.

An investment in our Units involves certain risks. If any of these risks were to occur, our business, financial position, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our Units could decline and you could lose part or all of your investment.

The following section lists the key current risk factors as of the date of this filing that may have a direct and material impact on our business, financial position, results of operations and cash flows. We also recommend that investors read the "Risk Factors" sections of reports filed by each of Enterprise Products Partners and Energy Transfer Equity for more detailed information about risks specific to these investments that may impact our business, financial position, results of operations and cash flows.

Risks Inherent in an Investment in the Parent Company

The Parent Company's operating cash flow is derived primarily from cash distributions it receives from each of the MLP Entities and EPGP.

The Parent Company's operating cash flow is derived primarily from cash distributions it receives from each of Enterprise Products Partners, Energy Transfer Equity (collectively, "the MLP Entities") and EPGP. The amount of cash that each MLP Entity can distribute to its partners, including the Parent Company and its general partner, each quarter principally depends upon the amount of cash flow it generates from its operations, which will fluctuate from quarter to quarter based on, among other things, the:

§ volume of hydrocarbon products transported in its gathering and transmission pipelines;

§ throughput volumes in its processing and treating operations;

§ fees it charges and the margins it realizes for its various storage, terminaling, processing and transportation services;

§ price of natural gas, crude oil and NGLs;

§ relationships among natural gas, crude oil and NGL prices, including differentials between regional markets;

§ fluctuations in its working capital needs;

§ level of its operating costs, including reimbursements to its general partner;

§ prevailing economic conditions; and

§ level of competition in its business segments and market areas.

In addition, the actual amount of cash the MLP Entities will have available for distribution will depend on other factors, including:

§ the level of sustaining capital expenditures incurred;

§ its cash outlays for capital projects and acquisitions;

§ its debt service requirements and restrictions contained in its obligations for borrowed money; and

§ the amount of cash reserves required by EPGP and LE GP for the normal conduct of Enterprise Products Partners' and Energy Transfer Equity's businesses, respectively.

We do not have any direct or indirect control over the cash distribution policies of Energy Transfer Equity or its general partner, LE GP.

Because of these factors, the MLP Entities may not have sufficient available cash each quarter to continue paying distributions at their current levels. Furthermore, the amount of cash that each of the MLP Entities has available for cash distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. As a result, the MLP Entities may be able to make cash distributions during periods when it records losses and may not be able to make cash distributions during periods when it records net income. See sections relating to specific risk factors of each of the MLP Entities included below for a discussion of further risks affecting the MLP Entities' ability to generate distributable cash flow.

In the future, the Parent Company may not have sufficient cash to pay distributions at its current distribution level or to increase distributions.

Because the Parent Company's primary source of operating cash flow is from cash distributions received from the MLP Entities, the amount of distributions it is able to make to its unitholders may fluctuate based on the level of distributions each MLP Entity makes to its partners, including the Parent Company. The Parent Company cannot assure you that the MLP Entities will continue to make quarterly distributions at their current levels or will increase their quarterly distributions in the future. In addition, while the Parent Company would expect to increase or decrease distributions to its unitholders if the distributions received from the MLP Entities increase or decrease, the timing and amount of such changes in distributions, if any, will not necessarily be comparable to the timing and amount of any changes in distributions made by the MLP Entities to the Parent Company. Factors such as capital contributions, debt service requirements, general, administrative and other expenses, reserves for future distributions and other cash reserves established by the board of directors of EPE Holdings may affect the distributions the Parent Company makes to its unitholders. Prior to making any distributions to its unitholders, the Parent Company will reimburse EPE Holdings and its affiliates for all direct and indirect expenses incurred by them on the Parent Company's behalf. EPE Holdings has the sole discretion to determine the amount of these reimbursed expenses. The reimbursement of these expenses, in addition to the other factors listed above, could adversely affect the level of distributions the Parent Company makes to its unitholders. The Parent Company cannot guarantee that in the future it will be able to pay distributions or that any distributions it does make will be at or above its current level of quarterly distributions. The actual amount of cash that is available for distribution to the Parent Company's unitholders will depend on numerous factors, many of which are beyond the Parent Company's control or the control of EPE Holdings.

A significant amount of the cash distributions the Parent Company receives are associated with general partner IDRs. Should Enterprise Products Partners or ETP reduce their cash distributions to partners, this could have an adverse, disproportionate effect on the cash distributions the Parent Company receives relative to these IDRs. This could result in a reduction in cash distributions to the Parent Company's partners.

Restrictions in the Parent Company's credit facility could limit its ability to make distributions to its unitholders.

The Parent Company's credit facility contains covenants limiting its ability to take certain actions. This credit facility also contains covenants requiring the Parent Company to maintain certain financial ratios. The Parent Company is prohibited from making any cash distribution to its unitholders if such distribution would cause an event of default or otherwise violate a covenant under this credit facility. For more information about the Parent Company's credit facility, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 in this annual report.

The Parent Company's unitholders do not elect its general partner or vote on its general partner's officers or directors. Affiliates of the Parent Company's general partner currently own a sufficient number of Units to block any attempt to remove EPE Holdings as general partner.

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

Furthermore, if the Parent Company's unitholders are dissatisfied with the performance of its general partner, they currently have no practical ability to remove EPE Holdings or its officers or directors. EPE Holdings may not be removed except upon the vote of the holders of at least 66 2/3% of its outstanding Units. Because affiliates of EPE Holdings own more than one-third of the Parent Company's outstanding Units, EPE Holdings currently cannot be removed without the consent of such affiliates. As a result of this provision, the trading price of the Parent Company's Units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

The Parent Company may issue an unlimited number of limited partner interests without the consent of its unitholders, which will dilute your ownership interest in the Parent Company and may increase the risk that it will not have sufficient available cash to maintain or increase its per Unit distribution level.

The Parent Company's partnership agreement provides that it may issue an unlimited number of limited partner interests without the consent of its unitholders. Such Units may be issued on the terms and conditions established in the sole discretion of the Parent Company's general partner. Any issuance of additional Units would result in a corresponding decrease in the proportionate ownership interest in the Parent Company represented by, and could adversely affect market price of, Units outstanding prior to such issuance. The payment of distributions on these additional Units may increase the risk that the Parent Company will be unable to maintain or increase its current quarterly distribution.

The market price of the Parent Company's Units could be adversely affected by sales of substantial amounts of its Units in the public markets, including sales by its existing unitholders.

Sales by certain of the Parent Company's existing unitholders of a substantial number of its Units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of the Parent Company's Units or could impair its ability to obtain capital through an offering of equity securities. The Parent Company does not know whether any such sale would be made in the public market or in a private placement, nor does it know what impact such potential or actual sales would have on its Unit price in the future.

Risks arising in connection with the execution of the Parent Company's business strategy may adversely affect its ability to make or increase distributions and/or the market price of its Units.

In addition to seeking to maximize distributions from Enterprise Products Partners, a principal focus of the Parent Company's business strategy includes acquiring general partner interests and associated incentive distribution rights and limited partner interests in publicly traded partnerships and, subject to its business opportunity agreements, acquiring assets and businesses that may or may not relate to the MLP Entities' businesses. However, the Parent Company may not be able to grow through acquisitions if it is unable to identify attractive acquisition opportunities or acquire identified targets. In addition, increased competition for acquisition opportunities may increase the Parent Company's cost of making acquisitions or cause it to refrain from making acquisitions.

If the Parent Company is able to make future acquisitions, it may not be successful in integrating those acquisitions into its existing or future assets and businesses. Risks related to the Parent Company's acquisition strategy include but are not limited to:

- the creation of conflicts of interests and competing fiduciary obligations that may inhibit the Parent Company's ability to grow or make additional acquisitions;
- additional or increased regulatory or compliance obligations, including financial reporting obligations;
- delays or unforeseen operational difficulties or diminished financial performance associated with the integration of new acquisitions, and the resulting delayed or diminished cash flows from such acquisitions;
- inefficiencies and complexities that may arise due to unfamiliarity with new assets, businesses or markets;
- conflicts with regard to the sharing of management responsibilities and allocation of time among overlapping officers, directors and other personnel;
- the inability to hire, train or retain qualified personnel to manage and operate the Parent Company's growing business; and
- the inability to obtain required financing for the Parent Company's existing business and new investment opportunities.

To the extent the Parent Company pursues an acquisition that causes it to incur unexpected costs, or that fails to generate expected returns, its financial position, results of operations and cash flows may be adversely affected, and its ability to make distributions and/or the market price of its Units may be negatively impacted.

The control of the Parent Company's general partner may be transferred to a third-party without unitholder consent.

The Parent Company's general partner, in accordance with its partnership agreement, may transfer its general partner interest in the Parent Company without the consent of unitholders. In addition, the Parent Company may transfer its general partner interest to a third-party in a merger or sale of all or substantially all of its assets without the consent of the Parent Company's unitholders. Furthermore, there is no restriction in the Parent Company's partnership agreement on the ability of Dan Duncan LLC, as the sole member of EPE Holdings, to transfer its equity interest in EPE Holdings to a third-party. The new equity owner of the Parent Company's general partner would then be in a position to replace the directors and officers of EPE Holdings and to influence the decisions taken by the directors and officers of EPE Holdings.

Substantially all of the Parent Company's Units that are owned by EPCO and certain of its affiliates and a significant amount of the common units and all of the Class B units of Enterprise Products Partners that are owned by EPCO and certain of its affiliates are pledged as security under the credit facility of an affiliate of EPCO. Upon an event of default under this credit facility, a change in ownership or control of the Parent Company or Enterprise Products Partners could result.

Substantially all of the Parent Company's Units that are owned by EPCO and certain of its affiliates and a significant amount of the common units and all of the Class B units of Enterprise Products Partners (other than the 20,242,179 common units the Parent Company currently owns) that are owned or controlled by EPCO and certain of its privately held subsidiaries, are pledged as security under a credit facility of EPCO Holdings, Inc., a wholly owned indirect subsidiary of EPCO. This credit facility contains customary and other events of default relating to certain defaults of the borrower, the Parent Company, Enterprise Products Partners and other affiliates of EPCO. Upon an event of default, a change in control or ownership of the Parent Company or Enterprise Products Partners could occur.

Substantially all of the Parent Company's assets are pledged under its credit facilities.

Borrowings under the Parent Company's August 2007 Credit Agreement are secured by its ownership of (i) 20,242,179 common units of Enterprise Products Partners, (ii) 100% of the membership interests in EPGP and (iii) 38,976,090 common units of Energy Transfer Equity. The Parent Company's credit facilities contain customary and other events of default. Upon an event of default, the lenders under the Parent Company's credit facilities could foreclose on its assets, which would have a material adverse effect on the Parent Company's financial position, results of operations and cash flows. For additional information regarding the Parent Company's debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The Parent Company's general partner has a limited call right that may require you to sell your Units at an undesirable time or price.

If at any time the Parent Company's general partner and its affiliates own more than 90% of the Parent Company's outstanding Units, the Parent Company's general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to the Parent Company, to acquire all, but not less than all, of the Units held by unaffiliated persons at a price not less than the then current market price. As a result, the Parent Company's unitholders may be required to sell their Units at an undesirable time or price and may not receive any return on their investment. The Parent Company's unitholders may also incur a tax liability upon a sale of their Units. At March 1, 2010, affiliates of EPE Holdings, including Dan L. Duncan, EPCO and the Employee Partnerships, owned approximately 78.0% of the Parent Company's outstanding units.

The Parent Company depends on the leadership and involvement of key personnel for the success of its businesses.

The Parent Company depends on the leadership, involvement and services of key personnel. The loss of leadership and involvement or the services of certain key members of the Parent Company's senior management team, including Dan L. Duncan, could have a material adverse effect on the Parent Company's business, financial position, results of operations, cash flows and market price of its Units.

An increase in interest rates may cause the market price of the Parent Company's Units to decline.

An increase in interest rates and the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. At December 31, 2009, Parent Company debt was $1.08 billion, of which $250.0 million was at fixed interest rates and the remainder at variable interest rates, after giving effect to existing interest rate swap agreements. Reduced demand for the Parent Company's Units resulting from investors seeking other more favorable investment opportunities may cause the trading price of the Parent Company's Units to decline. Please also read the risk factor "Increases in interest rates could materially affect the MLP Entities' business, financial position, results of operations and cash flows" included within this Item 1A.

The MLP Entities may issue additional common units, which may increase the risk that the MLP Entities will not have sufficient available cash to maintain or increase their per unit distribution level.

Each of the MLP Entities has wide latitude to issue additional common units on terms and conditions established by each of their respective general partners. The payment of distributions on those additional common units may increase the risk that the MLP Entities will be unable to maintain or increase their per unit distribution level, which in turn may impact the available cash that the Parent Company has to distribute to its unitholders.

A unitholder's liability as a limited partner may not be limited, and the Parent Company's unitholders may have to repay distributions or make additional contributions to the Parent Company under certain circumstances.

Under Delaware law, the Parent Company's unitholders could be held liable for its obligations to the same extent as a general partner if a court determined that the right of limited partners to remove the Parent Company's general partner or to take other action under the Parent Company's partnership agreement constituted participation in the "control" of the Parent Company's business. Under Delaware law, EPE Holdings generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to EPE Holdings.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business.

Under certain circumstances, the Parent Company's unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, neither the Parent Company nor either of the MLP Entities may make a distribution to its unitholders if the distribution would cause the Parent Company or the MLP Entities' respective liabilities to exceed the fair value of their respective assets. Liabilities to partners on account of the partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of Units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of Units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the Parent Company's partnership agreement.

The Parent Company may have to take actions that are disruptive to its business strategy to avoid registration under the Investment Company Act of 1940.

The Investment Company Act of 1940, or Investment Company Act, requires registration for companies that are engaged primarily in the business of investing, reinvesting, owning, holding or trading in securities. Registration as an investment company would subject the Parent Company to restrictions that are inconsistent with its fundamental business strategy.

A company may be deemed to be an investment company if it owns investment securities with a fair value exceeding 40% of the fair value of its total assets (excluding governmental securities and cash items) on an unconsolidated basis, unless an exemption or safe harbor applies. Securities issued by companies other than majority-owned subsidiaries are generally counted as investment securities for purposes of the Investment Company Act. The Parent Company owns noncontrolling equity interests in certain entities, including Energy Transfer Equity and LE GP, that could be counted as investment securities. In the event the Parent Company acquires additional investment securities in the future, or if the fair value of its interests in companies that it does not control were to increase relative to the fair value of its controlled subsidiaries (e.g., Enterprise Products Partners), the Parent Company might be required to divest some of its non-controlled business interests, or take other action, in order to avoid being classified as an investment company. Similarly, the Parent Company may be limited in its strategy to make future acquisitions of general partner interests and related limited partner interests to the extent they are counted as investment securities.

If the Parent Company ceases to manage and control Enterprise Products Partners and is deemed to be an investment company under the Investment Company Act of 1940, it may either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC, or modify its organizational structure or its contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit the Parent Company's ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from its affiliates, restrict its ability to borrow funds or engage in other transactions involving leverage and require it to add additional directors who are independent of the Parent Company or its affiliates.

Moreover, treatment of the Parent Company as an investment company would prevent its qualification as a partnership for federal income tax purposes, in which case it would be treated as a corporation for federal income tax purposes. As a result, the Parent Company would pay federal income tax on its taxable income at the corporate tax rate, distributions to its unitholders would generally be taxed again as corporate distributions and none of its income, gains, losses or deductions available for distribution to unitholders would be substantially reduced. As a result, treatment of the Parent Company as an investment company would result in a material reduction in distributions to its unitholders, which would materially reduce the value of its Units.

The Parent Company's partnership agreement restricts the rights of unitholders owning 20% or more of its Units.

The voting rights of the Parent Company's unitholders are restricted by the provision in the Parent Company's partnership agreement stating that any Units held by a person that owns 20% or more of any class of Units then outstanding, other than EPE Holdings and its affiliates, cannot be voted on any matter. In addition, the Parent Company's partnership agreement contains provisions limiting the ability of its unitholders to call meetings or to acquire information about its operations, as well as other provisions limiting its unitholders' ability to influence the manner or direction of its management. As a result of this provision, the trading price of the Parent Company's Units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

Risks Relating to Conflicts of Interest

Conflicts of interest exist and may arise among the Parent Company, Enterprise Products Partners and their respective general partners and affiliates and entities affiliated with any general partner interests that the Parent Company may acquire in the future.

Conflicts of interest exist and may arise in the future as a result of the relationships among the Parent Company, Enterprise Products Partners and their respective general partners and affiliates. EPE Holdings is controlled by Dan Duncan LLC, of which Dan L. Duncan is the sole member. Accordingly, Mr. Duncan has the ability to elect, remove and replace the directors and officers of EPE Holdings. Similarly, through his indirect control of the general partner of Enterprise Products Partners, Mr. Duncan has the ability to elect, remove and replace the directors and officers of the general partner of Enterprise Products Partners.

EPE Holdings' directors and officers have fiduciary duties to manage the Parent Company's business in a manner beneficial to the Parent Company and its partners. However, all of EPE Holdings' executive officers and non-independent directors (excluding O.S. Andras and Randa Duncan Williams) also serve as executive officers or directors of EPGP and, as a result, have fiduciary duties to manage the business of Enterprise Products Partners in a manner beneficial to Enterprise Products Partners and its partners. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to Enterprise Products Partners, on the one hand, and the Parent Company, on the other hand, are in conflict. The resolution of these conflicts may not always be in the Parent Company's best interest or that of its unitholders.

Future conflicts of interest may arise among the Parent Company, Enterprise Products Partners and any entities whose general partner interests the Parent Company or its affiliates own or acquire. It is not possible to predict the nature or extent of these potential future conflicts of interest at this time, nor is it possible to determine how the Parent Company will address and resolve any such future conflicts of interest. However, the resolution of these conflicts may not always be in the Parent Company's best interest or that of its unitholders.

If the Parent Company is presented with certain business opportunities, Enterprise Products Partners (for itself or Duncan Energy Partners) will have the first right to pursue such opportunities.

Pursuant to the ASA, the Parent Company has agreed to certain business opportunity arrangements to address potential conflicts that may arise among the Parent Company, Enterprise Products Partners and the EPCO Group (which includes EPCO and its affiliates, but excludes EPE Holdings, the Parent Company, EPGP and Enterprise Products Partners and its subsidiaries, including Duncan Energy Partners,). If a business opportunity in respect of any assets other than equity securities, which we generally define to include general partner interests in publicly traded partnerships and similar interests and associated IDRs and limited partner interests or similar interests owned by the owner of such general partner or its affiliates, is presented to the EPCO Group, the Parent Company, EPE Holdings, EPGP or Enterprise Products Partners, then Enterprise Products Partners (for itself or Duncan Energy Partners) will have the first right to acquire such assets. The ASA provides, among other things, that Enterprise Products Partners (for itself or Duncan Energy Partners) will be presumed to desire to acquire the assets until such time as it advises the EPCO Group and the Parent Company that it has abandoned the pursuit of such business opportunity, and the Parent Company may not pursue the acquisition of such assets prior to that time. These business opportunity arrangements limit the Parent Company's ability to pursue acquisitions of assets that are not "equity securities."

EPE Holdings' affiliates may compete with the Parent Company.

The Parent Company's partnership agreement provides that its general partner will be restricted from engaging in any business activities other than acting as its general partner and those activities incidental to the ownership of interests in the Parent Company. However, except as provided in the Parent Company's partnership agreement and subject to certain business opportunity agreements, affiliates of EPE Holdings are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with the Parent Company.

Potential conflicts of interest may arise among EPE Holdings, its affiliates and the Parent Company. EPE Holdings and its affiliates have limited fiduciary duties to the Parent Company and its unitholders, which may permit them to favor their own interests to the detriment of the Parent Company and its unitholders.

At March 1, 2010, Dan L. Duncan, EPCO and their controlled affiliates, including the Employee Partnerships, owned approximately 78.0% of the Parent Company's outstanding Units, and Dan Duncan LLC owned 100% of EPE Holdings. Dan Duncan serves as EPE Holdings' Chairman as well as the Chairman of EPGP. Conflicts of interest may arise among EPE Holdings and its affiliates, on the one hand, and the Parent Company and its unitholders, on the other hand. As a result of these conflicts, EPE Holdings may favor its own interests and the interests of its affiliates over the interests of the Parent Company's unitholders. These conflicts include, among others, the following:

§ EPE Holdings is allowed to take into account the interests of parties other than the Parent Company, including EPCO, EPGP, Enterprise Products Partners and their respective affiliates and any general partners and limited partnerships acquired in the future in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to the Parent Company's unitholders;

§ EPE Holdings has limited its liability and reduced its fiduciary duties under the Parent Company's partnership agreement, while also restricting the remedies available to the Parent Company's unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing the Parent Company's Units, unitholders consent to various actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;

- § EPE Holdings determines the amount and timing of the Parent Company's investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to the Parent Company's unitholders;

- § EPE Holdings determines which costs incurred by it and its affiliates are reimbursable by the Parent Company;

- § the Parent Company's partnership agreement does not restrict EPE Holdings from causing the Parent Company to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on the Parent Company's behalf, so long as the terms of any such payments or additional contractual arrangements are fair and reasonable to the Parent Company;

- § EPE Holdings controls the enforcement of obligations owed to the Parent Company by it and its affiliates; and

- § EPE Holdings decides whether to retain separate counsel, accountants or others to perform services for the Parent Company.

The Parent Company's partnership agreement limits EPE Holdings' fiduciary duties to the Parent Company and its unitholders and restricts the remedies available to the Parent Company's unitholders for actions taken by EPE Holdings that might otherwise constitute breaches of fiduciary duty.

The Parent Company's partnership agreement contains provisions that reduce the standards to which its general partner would otherwise be held by state fiduciary duty law. For example, the Parent Company's partnership agreement:

- § permits EPE Holdings to make a number of decisions in its individual capacity, as opposed to in its capacity as the Parent Company's general partner, entitling EPE Holdings 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, the Parent Company, its affiliates or any limited partner;

- § provides that EPE Holdings is entitled to make other decisions in "good faith" if it reasonably believes that the decisions are in the Parent Company's best interests;

- § generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Audit, Conflicts and Governance ("ACG") Committee of the board of directors of EPE Holdings and not involving a vote of unitholders must be on terms no less favorable to the Parent Company than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to the Parent Company and that, in determining whether a transaction or resolution is "fair and reasonable," EPE Holdings may consider the totality of the relationships among the parties involved, including other transactions that may be particularly advantageous or beneficial to the Parent Company; and

- § provides that EPE Holdings and its officers and directors will not be liable for monetary damages to the Parent Company, its limited partners or assignees 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, willful misconduct or gross negligence.

In order to become a limited partner of our partnership, the Parent Company's unitholders are required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above.

EPGP controls Enterprise Products Partners and may influence cash distributed to the Parent Company.

Although the Parent Company is the sole member of EPGP, its control over Enterprise Products Partners' actions is limited. The fiduciary duties owed by EPGP to Enterprise Products Partners and its unitholders prevent the Parent Company from influencing EPGP to take any action that would benefit the Parent Company to the detriment of Enterprise Products Partners or its unitholders. For example, EPGP makes business determinations on behalf of Enterprise Products Partners that impacts the amount of cash distributed by Enterprise Products Partners to its unitholders and to EPGP, which in turn, affects the amount of cash distributions the Parent Company receives from Enterprise Products Partners and EPGP and consequently, the amount of distributions the Parent Company can pay to its unitholders.

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

The Parent Company has no officers or employees and relies solely on officers of its general partner and employees of EPCO. Certain of the Parent Company's officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in the Parent Company's or its unitholders' best interests. In addition, these overlapping officers and employees allocate their time among the Parent Company, EPCO and other affiliates of EPCO. These officers and employees face potential conflicts regarding the allocation of their time, which may adversely affect the Parent Company's business, financial position and results of operations.

The ASA governs business opportunities among entities controlled by EPCO, which includes the Parent Company and its general partner, Enterprise Products Partners and its general partner and Duncan Energy Partners and its general partner. For detailed information regarding how business opportunities are handled within the EPCO group of companies, see Item 13 of this annual report.

The Parent Company does not have a separate compensation committee, and aspects of the compensation of its executive officers and other key employees, including base salary, are not reviewed or approved by its independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for the Parent Company. For a discussion of our executive compensation policies and procedures, see Item 11 of this annual report.

Risks Relating to the MLP Entities' Business

Since the Parent Company's cash flows primarily consist exclusively of distributions from the MLP Entities, risks to the MLP Entities' businesses are also risks to the Parent Company. We have set forth below what we believe to be the material current risks, as of the date of this filing, to the MLP Entities' businesses, the occurrence of which could have a material adverse impact on the MLP Entities' financial performance and decrease the amount of cash they are able to distribute to the Parent Company, thereby impacting the amount of cash that the Parent Company is able to distribute to its unitholders. These key risks are not presented in terms of importance or level of risk to such entities. In some instances, each of the MLP Entities share similar risks. However, in some cases, certain risks are specific to the businesses of Enterprise Products Partners and Energy Transfer Equity. These risks are discussed separately, when necessary. Any risks related to Energy Transfer Equity will refer to the business of ETP since the business of Energy Transfer Equity is to receive distributions from ETP.

The interruption of cash distributions to the MLP Entities from their respective subsidiaries and joint ventures may affect their ability to satisfy their obligations and to make cash distributions to their partners.

Each of the MLP Entities is a partnership holding company with no business operations, and its operating subsidiaries conduct all of their operations and own all of their operating assets. The only significant assets that each MLP Entity owns are the ownership interests in its subsidiaries and joint ventures. As a result, each MLP Entity depends upon the earnings and cash flow of its subsidiaries and joint ventures and the distribution of that cash in order to meet its obligations and to allow it to make distributions to its partners. The ability of an MLP Entity's subsidiaries and joint ventures to make cash distributions may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

In addition, the charter documents governing each of the MLP Entities' joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of cash distributions. Some of the joint ventures in which each MLP Entity participates have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make cash distributions to the MLP Entities under certain circumstances. Accordingly, each of the MLP Entities' joint ventures may be unable to make cash distributions to them at current levels, if at all.

Changes in demand for and production of hydrocarbon products may materially adversely affect the MLP Entities' financial position, results of operations and cash flows.

The MLP Entities operate predominantly in the midstream energy sector, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil and refined products. As such, the financial position, results of operations and cash flows of each of the MLP Entities may be materially adversely affected by changes in the prices of hydrocarbon products and by changes in the relative price levels among hydrocarbon products. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which each of the MLP Entities provide services. An MLP Entity may also incur credit and price risk to the extent counterparties do not perform in connection with its marketing of natural gas, NGLs, propylene, refined products and/or crude oil.

Historically, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month contract in 2008 ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu. In 2009, the same index ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu.

Generally, the prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional uncontrollable factors. Some of these factors include:

- the level of domestic production and consumer product demand;
- the availability of imported oil and natural gas and action taken by foreign oil and natural gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and NGLs;
- the impact of conservation efforts;

§ the extent of governmental regulation and taxation of production; and

§ the overall economic environment.

The MLP Entities are exposed to natural gas and NGL commodity price risk under certain of their natural gas processing and gathering and NGL fractionation contracts that provide for their fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which may materially adversely affect their financial position, results of operations and cash flows. Volatility in commodity prices may also have an impact on many of the MLP Entities' customers, which in turn could have a negative impact on their ability to meet their obligations to the MLP Entities.

With respect to Enterprise Products Partners' Petrochemical & Refined Products Services segment, market demand and the revenues from these businesses can also be adversely affected by different end uses of the products they transport, market or store. For example:

§ demand for gasoline depends upon market price, prevailing economic conditions, demographic changes in the markets they 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.

A decline in the volume of natural gas, NGLs and crude oil delivered to the MLP Entities' facilities could adversely affect their financial position, results of operations and cash flows.

The MLP Entities' profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at their facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in domestic and international exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by the MLP Entities' facilities and other energy logistic assets.

The crude oil, natural gas and NGLs currently transported, gathered or processed at the MLP Entities' facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, the MLP Entities' facilities will need access to production from newly discovered properties. Many economic and business factors are beyond the MLP Entities' control and can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where the MLP Entities' facilities and other energy logistic assets are located could result in a decrease in volumes to the MLP Entities' offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on the MLP Entities' financial position, results of operations cash flows.

In addition, imported liquefied natural gas ("LNG") may become a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies may be imported through new LNG facilities that have currently been developed or new LNG facilities that have been announced to be developed over the next decade. We cannot predict which, if any, of these announced, but as yet unbuilt, projects will be constructed. In addition, anticipated increases in future natural gas supplies may not be made available to the MLP Entities' facilities and pipelines if (i) a significant number of these new projects fail to be developed with their announced capacity, (ii) there are significant delays in such development, (iii) they are built in locations where they are not connected to the MLP Entities' assets or (iv) they do not influence sources of supply on the MLP Entities' systems. If the expected increase in natural gas supply through imported LNG is not realized, projected natural gas throughput on the MLP Entities' pipelines would decline, which could have a material adverse effect on the MLP Entities' financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect the MLP Entities' financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect the MLP Entities' financial position, results of operations and cash flows. Decreases in such demand may be caused by general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that the MLP Entities transport.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, the MLP Entities' operating margin from selling isobutane could be reduced.

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

Acquisitions that appear to increase the MLP Entities' cash from operations may nevertheless reduce their cash from operations on a per unit basis.

Even if the MLP Entities make acquisitions that they believe increase their cash from operations, these acquisitions may nevertheless reduce their cash from operations on a per unit basis. Any acquisition involves assumptions that may not materialize and potential risks that may occur. These risks include the MLP Entities' inability to achieve their operating and financial projections or to integrate an acquired business successfully, the assumption of unknown liabilities for which they become liable, and the loss of key employees or key customers.

If either of the MLP Entities consummates any future acquisitions, their 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 they will consider in determining the application of these funds and other resources.

The MLP Entities may not be able to fully execute their growth strategies if they encounter illiquid capital markets or increased competition for investment opportunities.

Each of the MLP Entities has a growth strategy that contemplates the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance the ability to compete effectively and diversifying their asset portfolios, thereby providing more stable cash flow. Each of the MLP Entities regularly considers and pursues potential joint ventures, standalone projects or other transactions that they believe may present opportunities to realize synergies, expand their role in the energy infrastructure business and increase their market positions.

Each of the MLP Entities will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on either MLP Entity's access to capital may impair their ability to execute their respective strategies. If the cost of debt or equity capital becomes too expensive, the MLP Entities ability to develop or acquire accretive assets will be limited. The MLP Entities also may not be able to raise necessary funds on satisfactory terms, if at all.

Tightening of the credit markets may have a material adverse effect on the Parent Company and the MLP Entities by, among other things, decreasing our ability to finance expansion projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of new equity issued either by the Parent Company or the MLP Entities may be at a higher yield than historical levels, making additional equity issuances more expensive.

In addition, each of the MLP Entities competes for the types of assets and businesses they have historically purchased or acquired. Increased competition for a limited pool of assets could result in the MLP Entities losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit the affected MLP Entity's ability to fully execute its growth strategy. The inability of either MLP Entity to execute its growth strategy may materially adversely affect its ability to maintain or pay higher distributions in the future.

The global financial crisis and its ongoing effects may have impacts on our business and financial condition that we currently cannot predict.

We may face significant challenges if conditions in the financial markets revert to those that existed in the fourth quarter of 2008 and during 2009. The ability of the MLP Entities and their respective affiliates to access the capital markets may be severely restricted at a time when they would like, or need, to do so, which could have an adverse impact on their ability to meet capital commitments and achieve the flexibility needed to react to changing economic and business conditions. The credit crisis could have a negative impact on lenders or customers of the MLP Entities and their affiliates, causing such parties to fail to meet their obligations. Additionally, demand for the services and products of the MLP Entities and their affiliates depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Also, a decrease in demand for NGLs by the petrochemical and refining industries due to a decrease in demand for their products as a result of general economic conditions would likely impact demand for services and products of the MLP Entities and their affiliates. Any of these factors could lead to reduced usage of the pipelines and energy logistics services of the MLP Entities and their affiliates, which could have a material negative impact on our prospects.

Increases in interest rates could materially adversely affect the MLP Entities' business, financial position, results of operations and cash flows.

The MLP Entities have significant exposure to increases in interest rates. At December 31, 2009, Enterprise Products Partners had outstanding $11.35 billion of consolidated debt, of which approximately $1.34 billion, or 11.8%, was subject to variable interest rates, either as short-term or long-term variable-rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. Enterprise Products Partners has $54.0 million of 8.70% fixed-rate debt that matured on March 1, 2010, and $500.0 million of 4.95% fixed-rate senior notes maturing in June 2010. In 2011, 2012 and 2013, Enterprise Products Partners has $450.0 million, $1.0 billion and $1.2 billion, respectively, of senior notes maturing. In addition, Enterprise Products Partners' $1.75 billion revolving credit facility matures in 2012 and Duncan Energy Partners' revolving credit facility and term loan totaling $582.3 million mature in 2011. Energy Transfer Equity reported $7.79 billion of consolidated debt, which includes debt with variable interest rates, in its annual report for the period ended December 31, 2009.

From time to time, the MLP Entities may enter into additional interest rate swap arrangements, which could increase their exposure to variable interest rates. As a result, their financial position, results of operations and cash flows could be materially adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as the MLP Entities' limited partnership units. Any such reduction in demand for the MLP Entities' equity securities resulting from other more attractive investment opportunities may cause the trading price of their securities to decline.

Operating cash flows from the MLP Entities' capital projects may not be immediate.

The MLP Entities have announced and are engaged in several construction projects involving existing and new facilities for which they have expended or will expend significant capital, and their operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if an MLP Entity builds a new pipeline or platform or expands an existing facility, the design, construction, development and installation may occur over an extended period of time, and it may not receive any material increase in operating cash flow from that project until a period of time after it is placed in-service. If the MLP Entity experiences any unanticipated or extended delays in generating operating cash flow from these projects, it may be required to reduce or reprioritize its capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet its capital requirements.

The MLP Entities' debt level may limit their future, financial and operating flexibility.

The amount of either of the MLP Entities' future debt could have significant effects on its operations, including, among other things:

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

§ credit rating agencies may view its consolidated debt level negatively;

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

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

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

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

Each of the MLP Entities' ability to access capital markets to raise capital on favorable terms could be affected by its debt level, the amount of its debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade either of the MLP Entities' credit rating, then the MLP Entity could experience an increase in its borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of its common units. Such a development could adversely affect the MLP Entity's ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If either of the MLP Entities is unable to access the capital markets on favorable terms in the future, it might be forced to seek extensions for some of its short-term securities or to refinance some of its debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which the MLP Entities might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that such MLP Entity's leverage may adversely affect its future financial and operating flexibility and thereby impact its ability to pay cash distributions at expected levels.

The MLP Entities face competition from third parties in their midstream businesses.

Even if crude oil and natural gas reserves exist in the areas accessed by the MLP Entities' facilities and are ultimately produced, the MLP Entities may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. The MLP Entities compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

The MLP Entities' refined products, NGL and marine transportation businesses compete with other pipelines and marine transportation companies in the areas they serve. The MLP Entities also compete with trucks and railroads in some of the areas they serve. Substantial new construction of inland marine vessels could create an oversupply and intensify competition for the MLP Entities' marine transportation businesses. Competitive pressures may adversely affect the MLP Entities' tariff rates or volumes shipped.

The crude oil gathering and marketing business can be characterized by thin operating margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production has intensified competition among gatherers and marketers. Enterprise Products Partners' crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies, financial institutions with trading platforms and other companies in the areas where such MLP Entities' pipeline systems deliver crude oil and NGLs.

In the MLP Entities' natural gas gathering businesses, they encounter competition in obtaining contracts to gather natural gas supplies, particularly new supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and price arrangements. The MLP Entities' key competitors in the gas gathering segment include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers they serve, and those producers may also elect to construct proprietary gas gathering systems. If production delivered to either of the MLP Entities' gathering systems declines, its revenues from such operations will decline.

The use of derivative financial instruments could result in material financial losses by each of the MLP Entities.

Each of the MLP Entities historically has sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that either of the MLP Entities hedges its commodity price and interest rate exposures, it will forego the benefits it would otherwise experience if commodity prices or interest rates were to change in its 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 and continued into 2009, increase the risk of nonpayment or performance by the MLP Entities' hedging counterparties. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for a discussion of our derivative instruments.

The MLP Entities' businesses require 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 the MLP Entities' businesses, and their credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions, such as the credit crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment and nonperformance by customers, particularly for customers that are smaller companies. The MLP Entities manage their 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.

The MLP Entities' risk management policies cannot eliminate all commodity price risks. In addition, any non-compliance with their risk management policies could result in significant financial losses.

To enhance utilization of certain assets and their operating income, the MLP Entities purchase petroleum products. Generally, it is their 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, they 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 the MLP Entities' anticipated physical supply could expose them to risk of loss resulting from price changes if they are required to obtain alternative supplies to cover these transactions. The MLP Entities are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, they 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 their pipelines. In addition, the marketing operations of the MLP Entities involve the risk of non-compliance with their risk management policies. The MLP Entities cannot assure that their processes and procedures will detect and prevent all violations of their risk management policies, particularly if deception or other intentional misconduct is involved.

The MLP Entities' actual construction, development and acquisition costs could exceed forecasted amounts.

The MLP Entities may have significant expenditures for the development and construction of midstream energy infrastructure assets, including construction and development projects with significant logistical, technological and staffing challenges. They may not be able to complete these projects at the costs estimated at the time of each project's initiation or that are currently estimated. Similarly, force majeure events such as hurricanes along the Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Gustav and Ike in 2008.

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

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

§ the MLP Entity 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;

§ the MLP Entity will not receive any material increases in revenues until the project is completed, even though it may have expended considerable funds during the construction phase, which may be prolonged;

§ the MLP Entity may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;

§ since the MLP Entity is not engaged in the exploration for and development of natural gas reserves, it may not have access to third-party estimates of reserves in an area prior to its constructing facilities in the area. As a result, the MLP Entity may construct facilities in an area where the reserves are materially lower than it anticipates;

§ where the MLP Entity does rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves;

§ the completion or success of the MLP Entity's project may depend on the completion of a project that it does not control, such as a refinery, that may be subject to numerous of its own potential risks, delays and complexities; and

§ the MLP Entity may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may not be economical.

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

Each MLP Entity's growth strategy may adversely affect its results of operations if it does not successfully integrate and manage the businesses that it acquires or if it substantially increases its indebtedness and contingent liabilities to make acquisitions.

Each of the MLP Entities' growth strategy includes making accretive acquisitions. As a result, from time to time, each of the MLP Entities will evaluate and acquire assets and businesses that it believes complement its existing operations. Either of the MLP Entities may be unable to successfully integrate and manage businesses it acquires in the future. Either of the MLP Entities may incur substantial expenses or encounter delays or other problems in connection with its growth strategy that could negatively impact its financial position, results of operations and cash flows.

Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

§ difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

§ establishing the internal controls and procedures required to be maintained under the Sarbanes-Oxley Act of 2002;

§ managing relationships with new joint venture partners with whom we have not previously partnered;

- § experiencing unforeseen operational interruptions or the loss of key employees, customers or suppliers;

- § inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

- § diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, amortization and accretion expenses. As a result, the MLP Entities' capitalization and results of operations may change significantly following an acquisition. A substantial increase in either of the MLP Entities' indebtedness and contingent liabilities could have a material adverse effect on its financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail the MLP Entities' operations and otherwise materially adversely affect cash flow and, accordingly, affect the market price of their common units.

Some of the MLP Entities' operations involve risks of personal injury, property damage and environmental damage, which could curtail their operations and otherwise materially adversely affect cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 lbs per square inch. Enterprise Products Partners also operates crude oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. In addition, Enterprise Products Partners' marine transportation business is subject to additional risks, including the possibility of marine accidents and spill events.   From time to time, Enterprise Products Partners' octane enhancement facility may produce MTBE for export, which could expose it to additional risks from spill events. Virtually all of the MLP Entities' operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of their assets and customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane risk.

If one or more facilities that are owned by the MLP Entities or that deliver crude oil, natural gas or other products to them are damaged by severe weather or any other disaster, accident, catastrophe or event, the MLP Entities' operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply the MLP Entities' facilities or other stoppages arising from factors beyond their control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that the MLP Entities are a party to obligate such MLP Entities' to indemnify customers for any damage or injury occurring during the period in which the customers' products is in their possession. Any event that interrupts the revenues generated by the MLP Entities' operations, or which causes them to make significant expenditures not covered by insurance, could reduce cash available for paying distributions and, accordingly, adversely affect the market price of their common units.

We believe that the MLP Entities have adequate insurance coverage, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of the MLP Entities' products. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, change in the insurance markets subsequent to the hurricanes in 2005 and 2008 have made it more difficult to obtain certain types of coverage. As a result, EPCO and LE GP may not be able to renew existing insurance policies on behalf of the MLP Entities or procure other desirable insurance on commercially reasonable terms, if at all. If the MLP Entities were to incur a significant liability for which they were not fully insured, a material adverse effect on their financial position, results of operations and cash flows could occur. 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.

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

The FERC regulates the MLP Entities' interstate natural gas pipelines and natural gas storage facilities under the NGA, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates the MLP Entities' interstate propylene pipelines. State regulatory agencies regulate the MLP Entities' intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the NGA, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for the services, terms and condition of service and certification and construction of new facilities. The FERC requires that the MLP Entities' services are provided on a non-discriminatory basis so that all shippers have open access to their pipelines and storage. Pursuant to the FERC's jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC and proposed rate increases may be challenged by protest.

The MLP Entities' intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the NGPA. The MLP Entities also have intrastate natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

Although the MLP Entities' natural gas gathering systems are generally exempt from FERC regulation under the NGA, FERC regulation still significantly affects their 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 the MLP Entities are able to charge in the future. In addition, the MLP Entities' 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 the MLP Entities 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. The MLP Entities cannot predict what effect, if any, such regulatory changes and legislation might have on their operations, but they could be required to incur additional capital expenditures.

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 Enterprise Products Partners' 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, 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.

ETP's pipeline operations are subject to ratable take and common purchaser statutes in Texas and Louisiana. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting ETP's right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which ETP operates have adopted complaint-based or other limited economic regulation of natural gas gathering activities which generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. Other state and local regulations also affect ETP's business.

ETP's and Enterprise Products Partners' intrastate storage facilities are subject to the jurisdiction of the Texas Railroad Commission ("TRRC"). Generally, the TRRC has jurisdiction over all underground storage of natural gas in Texas, unless the facility is part of an interstate gas pipeline facility. Because ETP's ET Fuel System and the HPL System natural gas storage facilities are only connected to intrastate gas pipelines, they fall within the TRRC's jurisdiction and must be operated pursuant to TRRC permit. Certain changes in ownership or operation of TRCC–jurisdictional storage facilities, such as facility expansions and increases in the maximum operating pressure, must be approved by the TRRC through an amendment to the facility's existing permit. In addition, the TRRC must approve transfers of the permits. The TRRC's regulations also require all natural gas storage facilities to be operated to prevent waste, the uncontrolled escape of gas, pollution and danger to life or property. Accordingly, the TRRC requires natural gas storage facilities to implement certain safety, monitoring, reporting and record-keeping measures. Violations of the terms and provisions of a TRRC permit or a TRRC order or regulation can result in the modification, cancellation or suspension of an operating permit and/or civil penalties, injunctive relief, or both. The TRRC's jurisdiction extends to both rates and pipeline safety. The rates the MLP Entities charge for transportation and storage services are deemed just and reasonable under Texas law unless challenged in a complaint. Should a complaint be filed or should regulation become more active, the MLP Entities' business may be adversely affected.

The MLP Entities' rates are subject to review and possible adjustment by federal and state regulators, which could have a material adverse effect on their 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 the MLP Entities' 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 the 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. Due to the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of either of the MLP Entities' rates could adversely affect their revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the producer price index for finished goods. As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, Market-Based Rates or agreements with all of the pipeline's shippers that the rate is acceptable. These methodologies may limit an MLP Entity's ability to set rates based on its 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 an MLP Entity's application of that methodology, could adversely affect it. Adverse decisions by the FERC in approving an MLP Entity's regulated rates could adversely affect its cash flow.

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

The partnership status of the MLP Entities may be a disadvantage to them in calculating their cost of service for rate-making purposes.

In May 2005, the 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 the FERC on a case-by-case basis. In December 2005, the FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership's rate case. The 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 the FERC's new tax allowance policy and the application of that policy in the December 2005 order.

In December 2006, the 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 the FERC characterized as a "tax savings." The 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, the 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.

In April 2008, the FERC issued a Policy Statement in which it declared that it would permit master limited partnerships ("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 the 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. The outcome of these ongoing proceedings could adversely affect the MLP Entities' revenues for any of their rates that are calculated using cost of service rate methodologies.

Enterprise Products Partners' marine transportation business would be adversely affected if it failed to comply with the Jones Act provisions on coastwise trade, or if those provisions were modified, repealed or waived.

Enterprise Products Partners is 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. If it does not comply with these restrictions, it would be prohibited from operating its vessels in U.S. coastwise trade, and under certain circumstances it would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for its 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 Enterprise Products Partners' 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 Enterprise Products Partners' revenues and cash available for distribution.

The MLP Entities' pipeline integrity programs and periodic tank maintenance requirements may impose significant costs and liabilities on them.

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 HCAs. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. The majority of the costs to comply with this integrity management rule are associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. 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 HCAs can have a significant impact on the costs to perform integrity testing and repairs. The MLP Entities will continue their pipeline integrity testing programs to assess and maintain the integrity of their pipelines. The results of these tests could cause the MLP Entities to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of their pipelines.

In June 2008, the 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 the MLP Entities' 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 the MLP Entities to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of the MLP Entities' storage tanks.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could affect the MLP Entities' results of operations, cash flows and financial condition.

The MLP Entities' operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Further, the MLP Entities cannot ensure that existing environmental regulations will not be revised or that new regulations, such as regulations designed to reduce emissions of greenhouse gases, will not be adopted or become applicable to the MLP Entities. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

Each of the MLP Entities will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could increase some costs of the MLP Entities' operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Climate change regulation is one area of potential future environmental law development. Certain studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

On December 7, 2009, the EPA announced its findings that emissions of "greenhouse gases" present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of CAA regulations in anticipation of finalizing its endangerment findings that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. These regulations will require reporting for some of the MLP Entities' facilities, and additional EPA regulations expected to be adopted in 2010 will require other of the MLP Entities' facilities to report their greenhouse gas emissions, possibly beginning in 2012 for emissions occurring in 2011.

Also, on June 26, 2009, the U.S. House of Representatives passed the ACESA, which would establish an economy-wide cap-and-trade program to intended reduce U.S. emissions of "greenhouse gases." ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system.

Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, the adoption and implementation of any CAA regulations, and any future federal, state or local laws or implementing regulations that may be adopted to address greenhouse gas emissions, could require us to incur increased operating costs and could adversely affect demand for the crude oil, natural gas and other hydrocarbon products that the MLP Entities transport, store or otherwise handle in connection with their midstream services. The effect on the MLP Entities' operations could include increased costs to operate and maintain facilities, measuring and reporting of emissions, installing new emission controls on facilities, acquiring allowances to authorize greenhouse gas emissions, paying any taxes related to greenhouse gas emissions and administering and managing a greenhouse gas emissions program. While the MLP Entities may be able to include some or all of such increased costs in the rates charged by their pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond their control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

Enterprise Products Partners' 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 Enterprise Products Partners' marine operations. Some environmental laws often impose strict liability for remediation of spills and releases of oil and hazardous substances, which could subject Enterprise Products Partners to liability without regard to whether it was 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 Enterprise Products Partners' 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 Enterprise Products Partners increases its 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.

Global warming, if occurring, may also impact the MLP Entities' operations directly, including increased maintenance costs for their facilities, increased flooding and severe weather risks for their facilities that are located in low-lying areas and coastal regions, and reduced demand for hydrocarbon products that may reduce demand and volumes of the products that the MLP Entities process, transport, market and store.

The MLP Entities are subject to strict regulations at many of their facilities regarding employee safety, and failure to comply with these regulations could adversely affect their ability to make distributions to their unitholders.

The workplaces associated with the MLP Entities' facilities are subject to the requirements of OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that each MLP Entity maintain information about hazardous materials used or produced in its operations and that it provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on the MLP Entities' business, financial position, results of operations and ability to make distributions to their unitholders.

An impairment of goodwill and intangible assets could reduce the MLP Entities' net income.

At December 31, 2009, Enterprise Products Partners' balance sheet reflected $2.02 billion of goodwill and $1.06 billion of intangible assets. At December 31, 2009, Energy Transfer Equity's balance sheet reflected $775.1 million of goodwill and $389.7 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles ("GAAP") requires the MLP Entities to test goodwill and indefinite-lived intangible assets for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If either of the MLP Entities determines that any of its goodwill or intangible assets were impaired, it would be required to take an immediate charge to earnings with a correlative effect on partners' equity and balance sheet leverage as measured by debt to total capitalization.

The MLP Entities may be unable to cause their joint ventures to take or not to take certain actions unless some or all of the joint venture participants agree.

The MLP Entities participate in several joint ventures. Due to the nature of some of these arrangements, the participants have made substantial investments and, accordingly, have required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, the affected MLP Entity may be unable to cause any of its joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the affected MLP Entity or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in the affected MLP Entity being required to partner with different or additional parties.

Risks Relating to Energy Transfer Equity and ETP

The following risks are specific to Energy Transfer Equity and ETP. The following summaries are derived from the risk factors presented by Energy Transfer Equity in its filings with the SEC. We do not control Energy Transfer Equity or ETP, and accordingly rely in large part on information, including risk factors, provided by Energy Transfer Equity in identifying and describing the risks set forth below.

A reduction in ETP's distributions will disproportionately affect the amount of cash distributions to which Energy Transfer Equity and we are entitled.

Energy Transfer Equity's indirect ownership of 100% of the IDRs in ETP, through its ownership of equity interests in the general partner of ETP, the holder of the IDRs, entitles Energy Transfer Equity to receive its pro rata share of specified percentages of total cash distributions made by ETP as it reaches established target cash distribution levels. Energy Transfer Equity currently receives its pro rata share of cash distributions from ETP based on the highest incremental percentage, 48%, to which the general partner of ETP is entitled pursuant to its IDRs in ETP. A decrease in the amount of distributions by ETP to less than $0.4125 per ETP common unit per quarter would reduce the general partner of ETP's percentage of the incremental cash distributions above $0.3175 per ETP common unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from ETP would have the effect of disproportionately reducing the amount of all distributions that Energy Transfer Equity receives from ETP based on its ownership interest in the IDRs in ETP as compared to cash distributions Energy Transfer Equity receives from ETP on its general partner interest in ETP (representing a 1.9% interest as of December 31, 2009) and its ETP common units. Any such reduction would reduce the amounts that Energy Transfer Equity could distribute to us directly and indirectly through our equity interests in its general partner.

Tax Risks to Our Unitholders

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

The anticipated after-tax benefit of an investment in our Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter. The value of our investment in the MLP Entities depends largely on each of the MLP Entities being treated 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 taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the after-tax return to our unitholders, likely causing a substantial reduction in the value of our Units.

If either of the MLP Entities were treated as a corporation for federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate. Distributions to us would generally be taxed again as corporate distributions, and no income, gains, losses, deduction or credits would flow through to us. As a result, there would be a material reduction in our anticipated cash flow, likely causing a substantial reduction in the value of our Units.

Current law may change, causing us or either of the MLP Entities to be treated as a corporation for federal income tax purposes or otherwise subjecting us or either of the MLP Entities to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to enhance state-tax collections. If any additional state were to impose an entity-level tax upon us or the MLP Entities as an entity, the cash available for distribution to our unitholders would be reduced.

The tax treatment of publicly traded partnerships or an investment in our Units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us and the MLP Entities, or an investment in our Units 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 exception, which we refer to as the qualifying income exception, for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, 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 recent public offerings of interests in the management operations of private equity funds and hedge funds, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704 of the Internal Revenue Code and changing the treatment of certain types of income earned from profits or "carried interests" in partnerships. In particular, the Tax Extenders Act of 2009 passed by the House of Representatives on December 9, 2009 recharacterizes certain income and gain received with respect to "investment service partnership interests" as ordinary income for the performance of services, which may not be treated as qualifying income for publicly traded partnerships unless substantially all of the assets of such partnership consist of interests in one or more publicly traded partnership and substantially all of the income of such partnership is ordinary income or Section 1231 gain. As such proposal is currently interpreted, a significant portion of our interest in the MLP Entities may be viewed as an investment service partnership interest. Moreover, the same proposal could change the tax treatment of future sales of our Units. Finally, the President's budget for the fiscal year 2011 also outlines proposals to tax carried interests as ordinary income. Although we are unable to predict whether the proposed legislation, or any other proposals, will ultimately be enacted and if so, whether any such proposed legislation would be applied retroactively, the enactment of any such proposed legislation could negatively impact the value of an investment in our Units.

A successful IRS contest of the federal income tax positions taken by either of the MLP Entities may adversely impact the market for its common units, and the costs of any contest will be borne by such MLP Entity, and therefore indirectly by us and the other unitholders of the MLP Entities.

The IRS may adopt positions that differ from the positions each of the MLP Entities takes, even positions taken with the advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions such MLP Entity takes. A court may not agree with all of the positions such MLP Entity takes. Any contest with the IRS may materially and adversely impact the market for the MLP Entities' common units and the prices at which the common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees will be borne by the MLP Entities and therefore indirectly by us, as a unitholder of such MLP Entity, and by the other unitholders of the MLP Entities.

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

Our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

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

If our unitholders sell their Units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those Units. Prior distributions in excess of the total net taxable income allocated to a unitholder for a Unit, which decreased his tax basis in that Unit, will, in effect, become taxable income if the Unit is sold at a price greater than such unitholder's tax basis in that Unit, even if the price received is less than such unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders.

Tax-exempt entities and non-U.S. 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 (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations 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 income tax returns and pay tax on their share of our taxable income.

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

Because we cannot match transferors and transferees of Units, we will adopt depreciation and amortization positions that may not conform with 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 your sale of Units and could have a negative impact on the value of our Units or result in audit adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of the Units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular Unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of the Units each month based upon the ownership of the 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, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations are issued, we may be required to change the allocation of items of income, gain, loss and deduction amount our unitholders.

The publicly traded partnerships in which we own interests have adopted certain methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders of these publicly traded partnerships. The IRS may challenge this treatment, which could adversely affect the value of the units of a publicly traded partnership in which we own interests and our Units.

When we, or an MLP Entity, issue additional equity securities or engage in certain other transactions, the applicable MLP Entity determines the fair market value of its assets and allocates any unrealized gain or loss attributable to such assets to the capital accounts of the MLP Entity's public unitholders and the MLP Entity's general partner. This methodology may be viewed as understating the value of the applicable MLP Entity's assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner of the MLP Entity, which may be unfavorable to such unitholders. Moreover, under this methodology, subsequent purchasers of our units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to an MLP Entity's intangible assets and a lesser portion allocated to an MLP Entity's tangible assets. The IRS may challenge these methods, or our or an MLP Entity's allocation of income, gain, loss and deduction between the general partner of the MLP Entity and certain of the MLP Entity's public unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of gain on the sale of units by our unitholders or an MLP Entity's unitholders and could have a negative impact on the value of our units or those of an MLP Entity or result in audit adjustments to the tax returns of our or an MLP Entity's unitholders without the benefit of additional deductions.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we or each of the MLP Entities do business or own property. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We or the MLP Entities may own property or conduct business in other states or foreign countries in the future. It is the responsibility of each unitholder to file its own federal, state and local tax returns.

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

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

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, he 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 he 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. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose Units are loaned to a short seller to cover a short sale of Units; therefore, 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 borrowing their Units.

Item 1B. *Unresolved Staff Comments*.

None.

Item 3. *Legal Proceedings*.

On occasion, we or our unconsolidated affiliates are named as defendants in legal proceedings relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows. For detailed information regarding our legal proceedings, see Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which is incorporated by reference into this Item 3.

Item 4. [Reserved]

PART II

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

Market Information and Cash Distributions

Our Units are listed on the NYSE under the ticker symbol "EPE." As of February 1, 2010, there were approximately 35 unitholders of record of our Units. The following table presents the high and low sales prices for our Units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our Units with respect to such periods.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2008					
1st Quarter	$ 36.86	$ 27.86	$ 0.4250	Apr. 30, 2008	May 8, 2008
2nd Quarter	$ 33.76	$ 29.51	$ 0.4400	Jul. 31, 2008	Aug. 8, 2008
3rd Quarter	$ 30.64	$ 21.16	$ 0.4550	Oct. 31, 2008	Nov. 13, 2008
4th Quarter	$ 24.20	$ 14.50	$ 0.4700	Jan. 30, 2009	Feb. 10, 2009
2009					
1st Quarter	$ 23.94	$ 17.67	$ 0.4850	Apr. 30, 2009	May 11, 2009
2nd Quarter	$ 29.60	$ 22.04	$ 0.5000	Jul. 31, 2009	Aug. 10, 2009
3rd Quarter	$ 31.27	$ 24.21	$ 0.5150	Oct. 30, 2009	Nov. 6, 2009
4th Quarter	$ 39.51	$ 29.16	$ 0.5300	Jan. 29, 2010	Feb. 5, 2010

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our unitholders) occur within 50 days after the end of such quarter. We expect to fund our quarterly cash distributions to our unitholders primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2009. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our Units.

Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

None.

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

The following table presents selected historical consolidated financial data for the Partnership. Information presented with respect to the years ended December 31, 2009, 2008 and 2007 and at December 31, 2009 and 2008 should be read in conjunction with the audited financial statements included under Item 8 of this annual report. Information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts are in millions (except per unit data).

	For Year Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Results of operations data: (1)					
Revenues	$ 25,510.9	$ 35,469.6	$ 26,713.8	$ 23,612.2	$ 20,858.2
Income from continuing operations (2)	$ 1,140.3	$ 1,145.1	$ 762.0	$ 772.4	$ 561.1
Net income	$ 1,140.3	$ 1,145.1	$ 762.0	$ 772.4	$ 560.9
Net income attributable to Enterprise GP Holdings L.P.	$ 204.1	$ 164.0	$ 109.0	$ 134.0	$ 82.2
Earnings per Unit:					
Basic and diluted (3)	$ 1.48	$ 1.33	$ 0.97	$ 1.30	$ 0.90
Other financial data:					
Distributions per Unit (4)	$ 2.03	$ 1.79	$ 1.55	$ 1.29	$ 0.37

	As of December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Financial position data: (1)					
Total assets	$ 27,686.3	$ 25,780.4	$ 24,084.4	$ 19,120.1	$ 17,483.9
Long-term and current maturities of debt (5)	$ 12,427.9	$ 12,714.9	$ 9,861.2	$ 7,053.9	$ 6,493.3
Equity (4)	$ 10,473.1	$ 9,759.4	$ 9,530.0	$ 8,968.7	$ 8,063.6
Total Units outstanding (4)	139.2	123.2	112.3	103.1	91.8

(1) In general, our historical results of operations and financial position have been affected by business combinations, asset acquisitions and other capital spending. In May 2007, the Parent Company acquired non-controlling interests in both Energy Transfer Equity and LE GP.

(2) Amounts presented are before the cumulative effect of changes in accounting principles.

(3) For information regarding our earnings per unit for the years ended December 31, 2009, 2008 and 2007, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(4) For additional information regarding our cash distributions, equity and Units outstanding, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(5) In general, our consolidated debt has increased over time as a result of financing all or a portion of acquisitions and other capital spending.

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

For the years ended December 31, 2009, 2008 and 2007.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes included in this annual report. Our discussion and analysis includes the following:

§ Cautionary Note Regarding Forward-Looking Statements.

§ Overview of Business.

§ Basis of Financial Statement Presentation.

§ Significant Recent Developments – Discusses significant developments during the year ended December 31, 2009 and through the date of this filing.

§ General Outlook for 2010.

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

§ Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.

§ Critical Accounting Policies and Estimates.

§ Other Items – Includes information related to contractual obligations, off-balance sheet arrangements and other matters.

Our financial statements have been prepared in accordance with U.S. GAAP.

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in the annual report speak only as of the date hereof. Except as required by 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.

Overview of Business

We are a publicly traded Delaware limited partnership, the limited partnership interests (the "Units") of which are listed on the NYSE under the ticker symbol "EPE." Our business consists of the ownership of general and limited partner interests of publicly traded partnerships engaged in the midstream energy industry and related businesses. Our goal is to increase cash distributions to unitholders.

The Parent Company is owned 99.99% by its limited partners and 0.01% by its general partner, EPE Holdings. EPE Holdings is a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. The Parent Company has no operations apart from its investing activities and indirectly overseeing the management of the entities controlled by it. At December 31, 2009 the Parent Company had investments in Enterprise Products Partners, Energy Transfer Equity and their respective general partners.

See Note 22 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for financial information regarding the Parent Company on a standalone basis.

In connection with the TEPPCO Merger, we revised our business segments. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services and (vi) Other Investments. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

Basis of Financial Statement Presentation

In accordance with rules and regulations of the U.S Securities and Exchange Commission ("SEC") and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of the financial information of businesses that we control through the ownership of general partner interests (e.g., Enterprise Products Partners). Our general purpose consolidated financial statements present those investments in which we do not have a controlling interest as unconsolidated affiliates (e.g., Energy Transfer Equity and LE GP). As presented in our consolidated financial statements, noncontrolling interest reflects third-party and related party ownership of our consolidated subsidiaries, which include the third-party and related party unitholders of Enterprise Products Partners and Duncan Energy Partners other than the Parent Company. Unless noted otherwise, our discussions and analysis in this annual report are presented from the perspective of our consolidated businesses and operations.

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of EPCO and its affiliates, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are reflected as "Former owners of TEPPCO," a component of noncontrolling interest.

The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

Significant Recent Developments

Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners

On October 26, 2009, the related mergers of wholly owned subsidiaries of Enterprise Products Partners with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 common units of Enterprise Products Partners for each TEPPCO unit. In total, Enterprise Products Partners issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP" have been delisted and are no longer publicly traded. On October 27, 2009, the TEPPCO and TEPPCO GP equity interests were contributed by Enterprise Products Partners to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 Class B units of Enterprise Products Partners in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as Enterprise Products Partners' common units.

Under the terms of the TEPPCO Merger agreements, the Parent Company received 1,331,681 common units of Enterprise Products Partners and an increase in the capital account of EPGP to maintain its 2% general partner interest in Enterprise Products Partners as consideration for 100% of the membership interests of TEPPCO GP.

In connection with the TEPPCO Merger, EPO commenced offers in September 2009 to exchange all of TEPPCO's outstanding notes (a combined principal amount of $2 billion) for a corresponding series of new EPO notes. The purpose of the exchange offer was to simplify our capital structure following the TEPPCO Merger. The exchanges for tendered TEPPCO notes were completed on October 27, 2009. The new EPO notes are guaranteed by Enterprise Products Partners L.P. The EPO notes issued in the exchange were recorded at the same carrying value as the TEPPCO notes being replaced. Accordingly, we recognized no gain or loss for accounting purposes related to this exchange. All note exchange direct costs paid to third parties have been expensed. In addition to the debt exchange, we gained approval from the requisite TEPPCO noteholders to eliminate substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes. Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under TEPPCO's revolving credit facility.

Enterprise Products Partners and Duncan Energy Partners Announce Extension of Acadian Gas System into Haynesville Shale Supply Basin

In October 2009, Enterprise Products Partners and its affiliate, Duncan Energy Partners, announced plans for its jointly owned Acadian Gas System to extend its Louisiana intrastate natural gas pipeline system into northwest Louisiana to provide producers in the rapidly expanding Haynesville Shale natural gas supply basin with access to additional markets through connections with the Acadian Gas System in south Louisiana and nine major interstate natural gas pipelines ("Haynesville Extension"). The Haynesville Shale producing area is believed to cover approximately 2 million acres in northwest Louisiana, almost all of which is under lease. Production from the approximately 200 wells drilled to date is estimated at more than 1 Bcf/d. Over 400 locations are in various stages of drilling and completion with approximately 150 rigs now working in the region.

As currently designed, the Haynesville Extension will have the potential capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with the existing Acadian Gas System. The pipeline is expected to be in service during the third quarter of 2011.

The Acadian Gas System serves major natural gas markets along the Mississippi River corridor between Baton Rouge and New Orleans and has the ability to make physical deliveries into the Henry Hub. The Haynesville Extension will also have interconnects with major interstate pipelines including Florida Gas, Texas Eastern, Transco, Sonat, Columbia Gulf, Trunkline, ANR, Tennessee Gas and Texas Gas. Together with the capacity of the existing Acadian Gas System, the extension project will provide approximately 6.2 Bcf/d of redelivery capacity into an estimated 12 Bcf/d of available downstream pipeline takeaway capacity. Initially, the project will connect to nine Haynesville Shale producer locations in DeSoto and Red River parishes.

Along with providing much needed natural gas takeaway capacity for growing Haynesville production, the Haynesville Extension is expected to provide shippers the opportunity to benefit from additional pricing points and diverse service options and access to the south Louisiana marketplace. For producers, the more flexible contracting options associated with an intrastate pipeline environment is expected to help facilitate a seamless transaction for the producer from the field to the end user.

Currently, Duncan Energy Partners owns a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interest. Duncan Energy Partners and EPO are in discussions regarding the funding and related aspects of the Haynesville Extension project.

Enterprise Products Partners and TEPPCO Exit Texas Offshore Port System Partnership

In August 2008, our wholly owned subsidiaries together with Oiltanking formed TOPS. Effective April 16, 2009, our wholly owned subsidiaries dissociated (exited) from TOPS. As a result, operating costs and expenses and net income for the year ended December 31, 2009 reflect a non-cash charge of $68.4 million. This loss represented the forfeiture of our cumulative investment in TOPS through the date of dissociation and reflected our capital contributions to TOPS for construction in progress amounts.   On September 17, 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized an additional $66.9 million of expense during 2009 in connection with the payment of this cash settlement. The aggregate $135.3 million of charges recorded during 2009 were classified within the Offshore Pipelines & Services business segment.

General Outlook for 2010

Enterprise Products Partners

Commercial Outlook. We provide midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Factors that can affect the demand for our services include global and U.S. economic conditions, the demand for energy, the market price of energy, the cost to develop natural gas and crude oil reserves in the U.S. and the cost and availability of capital to energy companies to invest in drilling activities.

The global economic contraction that began in late 2007 appeared to show signs of stabilizing in the second half of 2009 with most of the twenty largest developed economies (“G20”) reporting quarter-over-quarter growth in real gross domestic product (“GDP”) beginning in the third quarter of 2009. However, approximately 65% of the G20 were still reporting year-over-year contraction in real GDP in 2009. The United States reported quarter-over-quarter real GDP growth of 2.2% and 5.7% for the third and fourth quarters of 2009, respectively, after five quarters of contraction in real GDP since the beginning of 2008. Real GDP growth for 2009 compared to 2008 was 0.1%.

Impacted by general economic conditions and price shock-induced conservation by consumers, U.S. demand for petroleum products and natural gas (as reported by the U.S. Energy Information

Administration) for the first ten months of 2009 decreased approximately 5.4% and 2.1%, respectively, from the same periods in 2008 and by approximately 11% and 1.5%, respectively, from the first ten months of 2007. Likewise, U.S. demand for petroleum products for transportation purposes (e.g., motor gasoline, distillate and jet fuel) for the first ten months of 2009 declined by 2.7% and 6.3% compared to the first ten months of 2008 and 2007, respectively. The rate of decline in U.S. demand for petroleum products since mid-2009 appears to be moderating and demand for natural gas since mid-2009 has increased by 1.5% compared to the same period in 2008.

Energy prices have generally rebounded with the recovery in demand, economic growth and stability in the capital markets. The average prices for West Texas Intermediate crude oil and Mont Belvieu ethane for December 2009 increased by approximately 82% and 120%, respectively, from December 2008; while natural gas at the Henry Hub in December 2009 decreased by 8% from December 2008. Notably, there has been a substantial change in the price relationship between natural gas and crude oil. In December 2008, natural gas was priced at 81% of crude oil on an energy equivalent basis compared to 41% in December 2009. We believe changes in the price relationships of crude oil and crude oil derivatives to natural gas and NGLs in the past year could lead to a long-term structural change in feedstock selection by the petrochemical industry.

During 2009 and the beginning of 2010, natural gas and NGLs have a significant price advantage over more costly crude oil and crude oil derivatives (such as naphtha). This has been primarily driven by (i) a decline in global crude oil production; (ii) more government-held acreage being off limits to non-sovereign energy companies; (iii) geopolitical risk; (iv) growing demand for crude oil by China and other developing countries; (v) the globalization of natural gas prices with more LNG facilities becoming operational; and (vi) the technological breakthroughs around the development of natural gas shale resource basins that have decreased finding and development costs.

For ethylene producers, the largest consumers of NGLs, this has meant that ethane and propane were their most consistently profitable feedstocks in 2009 and are forecasted to be so in 2010. This feedstock cost advantage and a weak U.S. dollar provided U.S. ethylene producers with a competitive advantage globally, especially relative to naphtha crackers in Europe and Asia. Per industry publications, approximately 24% of 2009 aggregate domestic production of high density polyethylene (“HDPE”), low density polyethylene (“LDPE”) and polyvinyl chloride (“PVC”) were for the export market.

U.S. ethylene producers responded by maximizing the use of NGLs as a feedstock, rationalizing some of their facilities and investing capital to modify their furnaces to crack more NGLs. The U.S. ethylene industry consumed almost 1.3 MMBbls/d of NGL feedstocks in December 2009, an 81% increase over 700 MBPD of NGLs consumed in December 2008. We estimate domestic crackers are in the process of adding approximately 100 MBPD of new capacity to crack ethane and propane through modifications to their existing facilities. Certain international ethylene crackers have reacted to the NGL feedstock cost advantage by importing propane to displace crude oil derivatives to feed their heavy crackers, including propane produced in the U.S.

Export ethylene derivative demand remains strong in early 2010, but is expected to moderate as Middle East production increases later this year. Chemical margins in the U.S. are also forecasted to compress due to increased competition, but overall demand for domestically produced ethylene is expected to decline only by approximately 1.5% to 48.3 billion lbs/year in 2010 and then increase 2.3% to 49.4 billion lbs/year in 2011. With the global recession abating, domestic demand is expected to increase, consuming the production that was sold into the export markets in 2008 and 2009.

Strong end user demand for NGLs and increases in NGL-rich natural gas production are expected to (i) keep our natural gas processing plants and NGL fractionators, pipelines and storage facilities operating at high utilization rates; (ii) provide attractive natural gas processing margins for our equity NGL production; and (iii) provide us with opportunities to invest capital to build new natural gas processing, NGL fractionation and pipeline facilities.

At the beginning of 2009, we had opportunities to purchase NGLs and sell them forward for delivery in late 2009 and early 2010 at attractive sales margins. To facilitate this activity, we utilized our NGL storage facilities and pipelines. At the beginning of 2010, these opportunities have largely diminished.

Natural gas prices have significantly declined from a peak of over $13.00 per MMBtu in mid-2008 to $5.35 per MMBtu in December 2009. This price decrease coupled with the residual impact of a higher cost of capital for certain energy companies has generally resulted in energy companies reducing their drilling capital expenditure budgets. This has led to a substantial decrease in the number of rigs drilling for natural gas in the U.S., declining from a peak of 1,606 rigs in August 2008 to a low of 665 rigs in July 2009 as natural gas prices approached a low of $1.88 per MMBtu in September 2009. The natural gas rig count has since rebounded to 878 rigs at the beginning of February 2010. Even though the total natural gas rig count has dropped by almost half, the substantial efficiencies of horizontal drilling in the non-conventional and shale supply basins have allowed producers to maintain overall natural gas deliverability. As a result, rig count is not necessarily a reliable indicator of the level of future natural gas production. The rig count has increased in the developing Haynesville Shale, Marcellus Shale and Eagle Ford Shale area where producers are drilling to hold recently executed leases. Generally, rig counts remain significantly below peak levels in areas with conventional natural gas reserves and areas where producers have leases held by production.

Certain of the large natural gas and NGL producing basins we serve have seen a significant decrease in rig count. In Wyoming, Colorado and New Mexico, rig counts at the end of 2009 had declined 52%, 66% and 49%, respectively, from peak levels during 2008. Given the number of wells waiting to be connected to our pipeline systems, the respective production decline curves and the decline in drilling activity, we believe the aggregate natural gas pipeline volumes transported on our Jonah Gas Gathering, Piceance Basin Gathering and San Juan Gathering systems for 2010 could range from an increase of 5% to a decrease of 5% compared to volumes transported in 2009. Since the end of 2009, the rig counts in Wyoming and New Mexico have increased by 14% and 12%, respectively. These areas have substantial, undeveloped non-conventional natural gas reserves with some of the lowest finding costs in the U.S. and are supported by existing pipeline infrastructure to transport the natural gas to market. We believe as U.S. natural gas supply and demand becomes more balanced and natural gas prices become less volatile these areas will have an increase in drilling activity to support, and potentially increase, current production levels.

In Texas, the rig count at the end of 2009 was 50% below peak levels during 2008. Since the end of 2009, the rig count in Texas has increased 13%. The rig count in the Barnett Shale area at the end of 2009 was approximately 55% below peak levels. While the Barnett Shale has a significant amount of undeveloped natural gas reserves at relatively low finding costs, much of the acreage under lease is held by production. Certain energy companies that were active in the Barnett Shale have elected to reallocate a portion of their capital resources in the near term to drill wells in the Haynesville Shale in Louisiana, the Marcellus Shale in Pennsylvania and West Virginia, and the Eagle Ford Shale in South Texas to secure recently acquired leases that are not held by production. Despite the lower rig count in the Barnett Shale and certain other areas of Texas, we expect transportation volumes on our Texas Intrastate System to increase by up to 10% in 2010 with volume growth principally attributable to a full year of operations for the Sherman Extension pipeline and the commencement of operations on the Trinity River Lateral during the third quarter of 2010. Both of these pipelines serve the Barnett Shale region.

South Texas has seen an increase in drilling activity attributable to the development of the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System. We have completed several small pipeline projects that enable us to gather, transport and process up to 300 MMcf/d of new natural gas production from the Eagle Ford Shale. Generally, energy companies have had early success in the Eagle Ford Shale and several have indicated they plan to accelerate their drilling programs. Production associated with this region includes crude oil, NGL-rich natural gas and lean natural gas. We believe there may be opportunities for us to invest capital to incrementally expand our natural gas pipeline, storage and processing facilities; NGL pipeline and fractionation facilities; and crude oil pipeline and storage facilities to facilitate production growth from this region.

The rig count in Louisiana has increased 14% since the end of 2008 primarily due to development activities in the Haynesville Shale area of northwest Louisiana. Based on industry success, natural gas production from this region is expected to grow rapidly over the next several years. In the fourth quarter of 2009, we announced that seven energy companies had executed long-term agreements to support the Haynesville Extension expansion of our Acadian Gas System. The Haynesville Extension is a 249-mile, 42-inch pipeline designed to transport up to 2.1 Bcf/d. Construction of the pipeline will begin in 2010 and is scheduled to be completed by the end of the third quarter of 2011.

With respect to our offshore Gulf of Mexico assets, we expect natural gas volumes handled by our Independence Hub platform and Trail pipeline to range from 700 BBtus/d to 800 BBtus/d. Our major crude oil pipelines are expected to transport up to an aggregate 20% increase in volumes as the result of a full year of operations from our Shenzi pipeline and additional volumes from many offshore production facilities that were either idle or in limited service for at least half of 2009 due to repairs to infrastructure damaged by Hurricanes Gustav and Ike in 2008.

Our refined products pipeline generally serves the Petroleum Administration for Defense District (“PADD”) 2 of the U.S. Demand for refined products in this region for 2009 decreased by approximately 8% and 19% from 2008 and 2007, respectively. Commensurately, refined products transportation volumes on our pipelines in 2009 declined by 6.7% and 15.3% compared to 2008 and 2007, respectively. We do not expect any significant improvement in refined product demand in 2010 in this region due to soft economic conditions and ongoing conservation.

We completed the TEPPCO Merger on October 26, 2009. Our commercial, engineering and operating teams have had early success in identifying opportunities to increase revenues and/or lower operating costs by incorporating the former TEPPCO assets into our integrated midstream system. We believe we will find additional opportunities in 2010.

Liquidity Outlook. The debt and equity capital markets have significantly improved since the beginning of 2009. The cost of Enterprise Products Partners’ term debt and equity capital has generally declined to pre-financial crisis levels. The availability of term debt and equity capital has also improved. The availability of credit commitments from most banks has also improved from a year ago; however, the cost of new bank debt is significantly higher than pre-crisis levels (by approximately 2% on borrowed money) and the term of bank capital is generally limited to no more than three years.

In January 2010, Enterprise Products Partners completed a public offering of 10,925,000 of its common units, which resulted in net proceeds of $343.1 million. Upon completion of that offering, Enterprise Products Partners had liquidity, unrestricted cash and capacity under its multi-year credit facility, of approximately $2 billion. Based on information currently available, Enterprise Products Partners estimates that its capital expenditures for 2010 will approximate $1.75 billion, which includes approximately $1.5 billion for growth capital projects and $250 million for sustaining capital expenditures. Sustaining capital expenditures in 2010 are expected to be higher than prior years primarily due to pipeline integrity projects on certain of Enterprise Products Partners’ pipelines. Enterprise Products Partners estimates sustaining capital expenditures for 2011 will be in the range of $210 million to $220 million.

In 2010, Enterprise Products Partners has two notes maturing totaling $554.0 million. A $54.0 million 8.70% note matured on March 1, 2010, and a $500.0 million 4.95% senior note matures on June 1, 2010. Enterprise Products Partners believes it will have sufficient liquidity and access to capital markets to refinance these maturities.

Enterprise Products Partners expects its proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate its businesses efficiently, and available borrowing capacity under its credit facilities, to provide it with a foundation to meet its anticipated liquidity and capital requirements in 2010. Enterprise Products Partners also believes it will be able to access the capital markets in 2010 to maintain financial flexibility. Based on information currently available to Enterprise Products Partners, it believes it will maintain its investment grade credit ratings and meet its loan covenant obligations in 2010.

Enterprise Products Partners has approximately $3.2 billion of senior notes maturing in the period beginning 2010 through the end of 2013. In addition, Enterprise Products Partners has a $282.3 million bank term loan and bank credit facilities with commitments totaling approximately $2.0 billion maturing during this time period. The U.S. government is expected to run substantial annual budget deficits, exceeding a trillion dollars that will require a corresponding issuance of debt by the U.S. Treasury from 2010 through 2013. The interest rate on U.S. Treasury debt has a direct impact on the cost of Enterprise Products Partners' debt. At this time, Enterprise Products Partners is uncertain what the impact of the large issuance of U.S. Treasury debt and the prevailing economic and capital market conditions will have on the cost and availability of capital. To date, Enterprise Products Partners has executed approximately $550.0 million of interest rate swaps to hedge a portion of its future debt issuance costs to refinance its debt that matures during the 2010 through 2013 time period. Enterprise Products Partners will continue to monitor and evaluate the condition of the capital market and interest rate risk with respect to refinancing these maturities and funding our capital expenditures.

Energy Transfer Equity (as excerpted from Energy Transfer Equity L.P.'s Form 10-K for the fiscal year ended December 31, 2009)

The following information was taken directly from the "Trends and Outlook" section under Item 7 of Energy Transfer Equity, L.P.'s annual report on Form 10-K for the year ended December 31, 2009. Within the context of the following quotes, references to "we," "us," and "our" mean Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include ETP. References to "Unitholders" mean the unitholders of Energy Transfer Equity, L.P. The following statements are the responsibility of the management of Energy Transfer Equity L.P. and we have not made any independent inquiry with respect to such matters.

"Economic forecasts indicate continued high storage levels combined with slow consumption growth are expected to keep natural gas prices from rising dramatically throughout 2010. We have mitigated much of the exposure to changing prices and demand within our operations. In our natural gas operations, a significant portion of our revenue continues to be derived from long-term fee-based arrangements, pursuant to which our customers pay us capacity reservation fees regardless of the volume of natural gas transported; however, we do recognize a portion of our revenue from fees based on actual volumes transported. In addition, we continue to evaluate and execute strategies to mitigate the impacts of changing prices. For example, during the second half of 2009, we began entering into hedges to lock in prices on a portion of our estimated volumes exposed to natural gas price risk within our intrastate transportation segment. These volumes include net retained fuel and a portion of volumes purchased at the wellhead from producers and sold at market prices. Approximately 79% of our estimated volumes exposed to natural gas price risk in 2010 is currently hedged.

With our liquid take-away capacity, we anticipate a slight increase in volumes of NGLs processed in 2010. We believe this will have a favorable impact on our fee-based business as producers will be motivated to take advantage of the favorable pricing.

ETP maintained its quarterly distributions per ETP Common Unit at a consistent rate, without increase, throughout 2009. Nevertheless, the distributions we received from ETP in 2009 increased through our ownership of the incentive distribution rights of ETP, as a result of ETP's issuance of additional ETP Common Units. We were therefore able to increase the distributions that we paid per ETE Common Unit in 2009. Our ability to increase our distributions going forward will be dependent on ETP's issuance of additional ETP Common Units and/or increases in its quarterly distribution per ETP Common Unit.

We and ETP are continuing our pursuit of growth through construction of new assets, expansion of our existing assets and through strategic acquisitions. To that end, we currently expect to spend between $1.2 billion and $1.3 billion for growth capital expenditures on a consolidated basis in 2010. We believe that we have sufficient liquidity to fund our announced growth projects in 2010; furthermore, we believe that our current liquidity position would provide us the financial flexibility to pursue accretive acquisitions of various sizes."

Results of Operations

Selected Price and Volumetric Data

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

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2007 Averages	$ 6.86	$ 72.24	$ 0.79	$ 1.21	$ 1.42	$ 1.49	$ 1.68	$ 0.52	$ 0.47
2008									
1st Quarter	$ 8.03	$ 97.82	$ 1.01	$ 1.47	$ 1.80	$ 1.87	$ 2.12	$ 0.61	$ 0.54
2nd Quarter	$ 10.94	$ 123.80	$ 1.05	$ 1.70	$ 2.05	$ 2.08	$ 2.64	$ 0.70	$ 0.67
3rd Quarter	$ 10.25	$ 118.22	$ 1.09	$ 1.68	$ 1.97	$ 1.99	$ 2.52	$ 0.78	$ 0.66
4th Quarter	$ 6.95	$ 59.08	$ 0.42	$ 0.80	$ 0.90	$ 0.96	$ 1.09	$ 0.37	$ 0.22
2008 Averages	$ 9.04	$ 99.73	$ 0.89	$ 1.41	$ 1.68	$ 1.72	$ 2.09	$ 0.62	$ 0.52
2009									
1st Quarter	$ 4.91	$ 43.31	$ 0.36	$ 0.68	$ 0.87	$ 0.97	$ 0.96	$ 0.26	$ 0.20
2nd Quarter	$ 3.51	$ 59.79	$ 0.43	$ 0.73	$ 0.93	$ 1.11	$ 1.21	$ 0.34	$ 0.28
3rd Quarter	$ 3.39	$ 68.24	$ 0.47	$ 0.87	$ 1.12	$ 1.19	$ 1.42	$ 0.48	$ 0.43
4th Quarter	$ 4.16	$ 76.19	$ 0.67	$ 1.09	$ 1.39	$ 1.49	$ 1.64	$ 0.50	$ 0.44
2009 Averages	$ 3.99	$ 61.88	$ 0.48	$ 0.84	$ 1.08	$ 1.19	$ 1.31	$ 0.39	$ 0.34

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service and Chemical Marketing Associates, Inc. (“CMAI”). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate as measured on the NYMEX.

The following table presents Enterprise Products Partners' significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account Enterprise Products Partners' ownership interests in certain joint ventures and reflect the periods in which it owned an interest in such operations. These statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	2,196	2,021	1,877
NGL fractionation volumes (MBPD)	461	441	405
Equity NGL production (MBPD)	117	108	88
Fee-based natural gas processing (MMcf/d)	2,650	2,524	2,565
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	10,435	9,612	8,465
Onshore Crude Oil Pipelines & Services, net:			
Crude oil transportation volumes (MBPD)	680	696	652
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,420	1,408	1,641
Crude oil transportation volumes (MBPD)	308	169	163
Platform natural gas processing (MMcf/d)	700	632	494
Platform crude oil processing (MBPD)	12	15	24
Petrochemical & Refined Products Services, net:			
Butane isomerization volumes (MBPD)	97	86	90
Propylene fractionation volumes (MBPD)	68	58	68
Octane enhancement production volumes (MBPD)	10	9	9
Transportation volumes, primarily refined products and petrochemicals (MBPD)	806	818	882
Total, net:			
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	3,990	3,704	3,574
Natural gas transportation volumes (BBtus/d)	11,855	11,020	10,106
Equivalent transportation volumes (MBPD) (1)	7,110	6,604	6,233

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

Comparison of Results of Operations

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

	For Year Ended December 31,		
	2009	2008	2007
Revenues	$ 25,510.9	$ 35,469.6	$ 26,713.8
Operating costs and expenses	23,565.8	33,618.9	25,402.1
General and administrative costs	182.8	144.8	131.9
Equity in income of unconsolidated affiliates	92.3	66.2	13.6
Operating income	1,854.6	1,772.1	1,193.4
Interest expense	687.3	608.3	487.4
Provision for income taxes	25.3	31.0	15.8
Net income	1,140.3	1,145.1	762.0
Net income attributable to noncontrolling interest	936.2	981.1	653.0
Net income attributable to Enterprise GP Holdings L.P.	204.1	164.0	109.0

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

	For Year Ended December 31, 2009	2008	2007
Gross operating margin by segment:			
NGL Pipelines & Services	$ 1,628.7	$ 1,325.0	$ 848.0
Onshore Natural Gas Pipelines & Services	501.5	589.9	493.2
Onshore Crude Oil Pipelines & Services	164.4	132.2	109.6
Offshore Pipeline & Services	180.5	187.0	171.6
Petrochemical & Refined Products Services	364.7	374.9	342.0
Other Investments	41.1	31.3	3.1
Total segment gross operating margin	$ 2,880.9	$ 2,640.3	$ 1,967.5

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, see "Other Items – Non-GAAP Reconciliations" included within this Item 7.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

	For Year Ended December 31, 2009	2008	2007
NGL Pipelines & Services:			
Sales of NGLs	$ 11,598.9	$ 14,573.5	$ 11,701.3
Sales of other petroleum and related products	1.8	2.4	3.0
Midstream services	708.3	737.9	746.4
Total	12,309.0	15,313.8	12,450.7
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,410.5	3,083.1	1,676.7
Midstream services	739.4	733.3	649.2
Total	3,149.9	3,816.4	2,325.9
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	7,110.6	12,696.2	9,048.5
Midstream services	80.4	67.6	55.3
Total	7,191.0	12,763.8	9,103.8
Offshore Pipelines & Services:			
Sales of natural gas	1.2	2.8	3.2
Sales of crude oil	5.3	11.1	12.1
Midstream services	333.4	254.5	208.5
Total	339.9	268.4	223.8
Petrochemical & Refined Products Services:			
Sales of other petroleum and related products	1,991.8	2,757.6	2,207.2
Midstream services	529.3	549.6	402.4
Total	2,521.1	3,307.2	2,609.6
Total consolidated revenues	$ 25,510.9	$ 35,469.6	$ 26,713.8

Our consolidated revenues are derived from a wide customer base. During 2009, our largest non-affiliated customer based on revenues was Shell, which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero, which accounted for 11.2% and 8.9%, respectively, of our revenues.

Comparison of 2009 with 2008

Revenues for 2009 were $25.51 billion compared to $35.47 billion for 2008. The $9.96 billion year-to-year decrease in consolidated revenues is primarily due to lower energy commodity sales prices during 2009 relative to 2008. This factor accounted for a $10.01 billion year-to-year decrease in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products marketing activities. Collectively, the remainder of our consolidated revenues increased $47.9 million year-to-year primarily due to improved results from our offshore activities. Revenues from our Offshore Pipelines & Services business segment for 2009 include aggregate property damage and business interruption insurance proceeds of $31.0 million.

Operating costs and expenses were $23.57 billion for 2009 compared to $33.62 billion for 2008, a $10.05 billion year-to-year decrease. The cost of sales of our marketing activities decreased $9.59 billion year-to-year primarily due to lower energy commodity sales prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $700.0 million year-to-year primarily due to lower plant thermal reduction ("PTR") costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for 2009 include $68.4 million of expenses related to the forfeiture of our interest in TOPS and $66.9 million of expenses related to the settlement of litigation involving TOPS. Collectively, the remainder of our consolidated operating costs and expenses increased $105.1 million year-to-year primarily due to higher depreciation expense and non-cash impairment charges recorded during 2009. General and administrative costs increased $38.0 million year-to-year primarily due to expenses we incurred during 2009 in connection with the TEPPCO Merger.

Changes in our revenues and costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $0.85 per gallon during 2009 versus $1.40 per gallon during 2008 – a 39% decrease year-to-year. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $3.99 per MMBtu during 2009 versus $9.04 per MMBtu during 2008 – a 56% decrease year-to-year. The market price of crude oil (as measured on the NYMEX) averaged $61.88 per barrel during 2009 compared to $99.73 per barrel during 2008 – a 38% decrease year-to-year. See "Selected Price and Volumetric Data" included within this Item 7 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $92.3 million for 2009 compared to $66.2 million for 2008, a $26.1 million year-to-year increase. Collectively, equity in income from our investments in Cameron Highway and Poseidon increased $13.8 million year-to-year due to higher crude oil transportation volumes. Equity in income from our investments in White River Hub, LLC ("White River Hub") and Skelly-Belvieu increased $3.1 million and $1.9 million year-to-year, respectively. The assets owned by White River Hub began commercial operations in December 2008. We acquired a 49% equity interest in Skelly-Belvieu during December 2008. Equity in income from our Marco Polo platform decreased $13.3 million year-to-year primarily due to the expiration of demand fee revenues during March 2009. The Marco Polo platform is owned through our investment in Deepwater Gateway. Equity in income from our investments in Energy Transfer Equity and its general partner, LE GP, increased $9.8 million year-to-year. Collectively, equity in income of our other investments increased $10.8 million year-to-year largely due to improved results from our investments in south Louisiana.

Operating income for 2009 was $1.85 billion compared to $1.77 billion for 2008. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $82.5 million year-to-year increase in operating income.

Interest expense increased to $687.3 million for 2009 from $608.3 million for 2008. The $79.0 million year-to-year increase in interest expense is primarily due to EPO's issuance of Senior Notes M and N in the second quarter of 2008, Senior Notes O in the fourth quarter of 2008 and a $37.6 million decrease in capitalized interest during 2009 relative to 2008. Average debt principal outstanding increased to $13.02 billion during 2009 from $11.27 billion during 2008 primarily due to debt incurred to fund growth capital investments.

Provision for income taxes decreased $5.7 million year-to-year primarily due to lower expenses associated with the Texas Margin Tax, partially offset by a one-time charge of $6.6 million associated with taxable gains arising from Dixie Pipeline Company's ("Dixie") sale of certain assets during 2009.

As a result of items noted in the previous paragraphs, our consolidated net income decreased $4.8 million year-to-year to $1.14 billion for 2009 compared to $1.15 billion for 2008. Net income attributable to noncontrolling interests was $936.2 million for 2009 compared to $981.1 million for 2008. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for more information regarding the year-to-year changes in net income attributable to noncontrolling interests. Net income attributable to Enterprise GP Holdings increased $40.1 million year-to-year to $204.1 million for 2009 compared to $164.0 million for 2008.

In general, Hurricanes Gustav and Ike had an adverse effect across our operations in the Gulf of Mexico and along the U.S. Gulf Coast during 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for 2008 includes $49.1 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin from Enterprise Products Partners' consolidated operations was reduced by approximately $81.0 million during 2008 due to the effects of Hurricanes Gustav and Ike as a result of supply interruptions and facility downtime. For more information regarding our insurance program and claims related to these storms, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.63 billion for 2009 compared to $1.33 billion for 2008, a $303.7 million year-to-year increase. Results for 2009 include $4.4 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds for 2008. The following paragraphs provide a discussion of segment results excluding the effect of cash proceeds from business interruption insurance.

Gross operating margin from our natural gas processing and related NGL marketing business was $948.8 million for 2009 compared to $815.3 million for 2008, a $133.5 million year-to-year increase. Equity NGL production increased to 117 MBPD during 2009 from 108 MBPD during 2008. The recently completed Meeker and Pioneer facilities and related hedging program contributed $104.7 million of the year-to-year increase in gross operating margin due to higher volumes and improved processing margins. These Rocky Mountain natural gas processing plants produced 60 MBPD of equity NGLs during 2009 compared to 49 MBPD during 2008. During 2009, we significantly increased the volume of forward sales transactions in connection with our NGL marketing activities resulting in higher sales margins and increased utilization of certain of our pipeline and storage facilities. Our NGL marketing activities contributed $95.7 million of the year-to-year increase in gross operating margin. Collectively, gross operating margin from the remainder of this business decreased $66.9 million year-to-year primarily due to lower NGL sales margins and equity NGL production volumes in Texas and New Mexico.

Gross operating margin from our NGL pipelines and related storage business was $539.5 million for 2009 compared to $397.4 million for 2008, a $142.1 million year-to-year increase. Total NGL transportation volumes increased to 2,196 MBPD during 2009 from 2,021 MBPD during 2008. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $85.7 million year-to-year due to a $26.4 million benefit in 2009 related to the Mid-America Pipeline System rate case settlement, an increase in the system-wide tariff, higher volumes and lower fuel costs. Gross operating margin from our NGL import/export terminal and related pipeline increased $20.3 million year-to-year primarily due to higher export volumes. Our Mont Belvieu storage complex contributed $14.9 million of the year-to-year increase in gross operating margin due to higher volumes and fees. Collectively, gross operating margin from the remainder of our NGL pipelines and related storage assets increased $21.2 million year-to-year primarily due to improved results from our south Louisiana assets.

Gross operating margin from our NGL fractionation business was $136.0 million for 2009 compared to $111.2 million for 2008. Gross operating margin from this business increased $24.8 million year-to-year primarily due to lower fuel costs and higher NGL fractionation volumes at our Mont Belvieu and South Louisiana fractionators during 2009 compared to 2008. Fractionation volumes were 461 MBPD during 2009 compared to 441 MBPD during 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $501.5 million for 2009 compared to $589.9 million for 2008, an $88.4 million year-to-year decrease. Our onshore natural gas transportation volumes were 10,435 BBtus/d during 2009 compared to 9,612 BBtus/d during 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $448.5 million for 2009 compared to $550.5 million for 2008, a $102.0 million year-to-year decrease. Gross operating margin from our San Juan gathering system decreased $106.4 million year-to-year primarily due to lower fees indexed to regional natural gas prices and condensate sales revenues as a result of the year-to-year decrease in commodity prices. Gross operating margin from our Texas Intrastate System decreased $14.4 million year-to-year. Contributions from the Sherman Extension pipeline of our Texas Intrastate System during 2009 were more than offset by a year-to-year increase in operating costs and expenses and lower revenues from the sale of pipeline condensate. Our Jonah gathering system contributed a $17.0 million year-to-year increase in gross operating margin primarily due to higher natural gas gathering volumes. Collectively, gross operating margin from the remainder of the businesses classified within this segment increased $1.8 million year-to-year primarily due to improved results from natural gas marketing during 2009 compared to 2008.

Gross operating margin from our natural gas storage business was $53.0 million for 2009 compared to $39.4 million for 2008. The $13.6 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed an additional natural gas storage cavern in operation during the third quarter of 2008 at our Petal facility, which provided an additional 4.2 Bcf of subscribed capacity.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $164.4 million for 2009 compared to $132.2 million for 2008, a $32.2 million year-to-year increase. Total onshore crude oil transportation volumes were 680 MBPD during 2009 compared to 696 MBPD during 2008. Gross operating margin from crude oil marketing activities increased $36.4 million year-to-year primarily due to higher sales volumes and margins during 2009 relative to 2008. Collectively, gross operating margin from our crude oil terminals in Cushing, Oklahoma and Midland, Texas increased $3.8 million year-to-year primarily due to higher storage revenues and throughput volumes. Gross operating margin from the remainder of the assets within this business segment decreased $8.0 million year-to-year primarily due to lower volumes and higher operating expenses on our South Texas System and lower equity in income from our investment in Seaway. The pipeline assets owned by Seaway experienced lower volumes and average fees during 2009 compared to 2008.

Offshore Pipelines & Services. Gross operating margin from this business segment was $180.5 million for 2009 compared to $187.0 million for 2008, a $6.5 million year-to-year decrease. Results for 2009 include $28.9 million of proceeds from business interruption insurance claims compared to $0.2 million of such proceeds in 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance proceeds.

Gross operating margin from our offshore crude oil pipeline business was a loss of $56.1 million for 2009 versus $35.1 million of earnings for 2008, a $91.2 million year-to-year decrease. Excluding $135.3 million of expenses related to TOPS recorded during 2009, gross operating margin from our offshore crude oil pipelines increased $44.1 million year-to-year primarily due to the start-up of our Shenzi crude oil pipeline in April 2009 and higher transportation volumes on our Poseidon crude oil pipeline.

Total offshore crude oil transportation volumes were 308 MBPD during 2009 versus 169 MBPD during 2008.

Gross operating margin from our offshore natural gas pipeline business was $65.1 million for 2009 compared to $6.9 million for 2008, a $58.2 million year-to-year increase. Offshore natural gas transportation volumes were 1,420 BBtus/d during 2009 versus 1,408 BBtus/d during 2008. Gross operating margin from our Independence Trail pipeline increased $39.8 million year-to-year. Results for 2008 were negatively impacted by expenses and downtime associated with flex joint repairs on the Independence Trail pipeline; whereas, results for 2009 include $8.7 million of insurance proceeds related to the flex joint repairs. Collectively, gross operating margin from our other offshore natural gas pipelines increased $18.4 million year-to-year primarily due to hurricane-related property damage repair expenses during 2008.

Gross operating margin from our offshore platform services business was $142.6 million for 2009 compared to $144.8 million for 2008, a $2.2 million year-to-year decrease. Gross operating margin from our Independence Hub platform increased $12.1 million year-to-year primarily due to an increase in natural gas processing volumes. Our Independence Hub platform experienced reduced volumes and downtime during 2008 in connection with the pipeline flex joint repairs. Collectively, gross operating margin from our other offshore platforms and related assets decreased $14.3 million year-to-year primarily due to lower natural gas and crude oil processing volumes at our Marco Polo platform as a result of prolonged hurricane-related disruptions and the expiration of demand fee revenues at our Marco Polo and Falcon platforms. Our net platform natural gas processing volumes increased to 700 MMcf/d during 2009 compared to 632 MMcf/d during 2008. Our net platform crude oil processing volumes decreased to 12 MBPD during 2009 compared to 15 MBPD during 2008.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $364.7 million for 2009 compared to $374.9 million for 2008, a $10.2 million year-to-year decrease.

Gross operating margin from octane enhancement was $11.5 million for 2009 compared to a loss of $11.3 million for 2008, a $22.8 million year-to-year increase. Gross operating margin for 2008 was negatively impacted by downtime, reduced volumes and higher operating expenses as a result of operational issues and the effects of Hurricane Ike.

Gross operating margin from propylene fractionation and related activities was $89.6 million for 2009 compared to $87.2 million for 2008. The $2.4 million year-to-year increase in gross operating margin is largely due to higher propylene sales volumes during 2009 relative to 2008. Propylene fractionation volumes increased to 68 MBPD during 2009 from 58 MBPD during 2008.

Gross operating margin from butane isomerization was $76.2 million for 2009 compared to $95.9 million for 2008. The $19.7 million year-to-year decrease in gross operating margin is primarily due to lower proceeds from the sale of plant by-products as a result of lower commodity prices. Butane isomerization volumes increased to 97 MBPD during 2009 from 86 MBPD during 2008.

Gross operating margin from refined products pipelines and related activities was $124.7 million for 2009 compared to $132.9 million for 2008, an $8.2 million year-to-year decrease. Gross operating margin for 2009 includes $28.7 million of expenses to accrue a liability for pipeline transportation deficiency fees owed to a third-party. Gross operating margin from the remainder of this business increased $20.5 primarily due to increased revenue from product sales, lower operating expenses and higher average fees on our Products Pipeline System during 2009 relative to 2008. Transportation volumes on our refined products pipelines were 682 MBPD during 2009 compared to 702 MBPD during 2008.

Gross operating margin from marine transportation and other services was $62.7 million for 2009 compared to $70.2 million for 2008, a $7.5 million year-to-year decrease. Gross operating margin from marine transportation decreased $4.8 million year-to-year due to higher operating expenses and lower day rates during 2009 relative to 2008. These factors more than offset gross operating margin generated by the acquisition of 19 push boats and 28 barges in June 2009. The utilization of our marine services fleet averaged 87% and 93% during 2009 and 2008, respectively. Gross operating margin from the distribution of lubrication oils and specialty chemicals decreased $2.7 million year-to-year primarily due to lower margins from the sale of specialty chemicals and higher operating expense during 2009 compared to 2008.

Other Investments. Gross operating margin from this business segment was $41.1 million for 2009 compared to $31.3 million for 2008, a $9.8 million year-to-year increase. This segment reflects the Parent Company's noncontrolling ownership interests in Energy Transfer Equity and its general partner, LE GP, both of which are accounted for using the equity method.

According to financial statements filed with the SEC, Energy Transfer Equity reported operating income of $1.11 billion for 2009 compared to $1.10 billion for 2008. The $11.5 million year-to-year increase in Energy Transfer Equity's operating income is primarily due to improved retail propane sales margins including the impact of hedging activities, contributions from recently completed growth capital projects (e.g., ETP's Phoenix project and increased intrastate pipeline transportation capacity) and lower fuel costs. The year-to-year increase in operating income attributable to the foregoing was partially offset by lower fuel retention revenues (associated with ETP's intrastate transportation and storage operating segment) as a result of lower average natural gas prices during 2009 relative to 2008. Collectively, all other items included in Energy Transfer Equity's net income increased $6.6 million year-to-year primarily due to changes in the fair value of non-hedged interest rate derivatives, the benefit of which was partially offset by a year-to-year increase in interest expense primarily due to borrowings used to finance growth capital projects. After taking into account noncontrolling interests, income attributable to the partners of Energy Transfer Equity increased to $442.5 million for 2009 from $375.0 million for 2008.

Before the amortization of excess cost amounts, our equity income from Energy Transfer Equity and LE GP was a collective $77.7 million for 2009 versus $65.6 million for 2008. Our equity income from these investments was reduced by $36.6 million and $34.3 million of excess cost amortization during 2009 and 2008, respectively. For additional information regarding our investments in Energy Transfer Equity and LE GP, see Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Comparison of 2008 with 2007

Revenues for 2008 were $35.47 billion compared to $26.71 billion for 2007. The $8.76 billion year-to-year increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during 2008 relative to 2007. These factors accounted for $8.47 billion of the year-to-year increase in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products marketing activities. Equity NGLs we produced at our newly constructed Meeker and Pioneer natural gas plants and sold in connection with our NGL marketing activities contributed $731.3 million of the year-to-year increase in marketing activity revenues. Collectively, the remainder of our consolidated revenues increased $281.1 million year-to-year primarily due to newly constructed assets we placed into service and recently acquired businesses, principally our Independence project and the marine transportation businesses.

Operating costs and expenses were $33.62 billion for 2008 versus $25.4 billion for 2007, an $8.22 billion year-to-year increase. The cost of sales of our marketing activities increased $7.11 billion year-to-year primarily due to higher energy commodity sales volumes and prices. Likewise, the operating costs and expenses of our natural gas processing plants increased $300.4 million year-to-year primarily due to higher energy commodity prices. Collectively, the remainder of our consolidated operating costs and expenses increased $808.7 million year-to-year primarily due to assets we constructed and placed into service or acquired since January 1, 2007. General and administrative costs increased $12.9 million year-to-year largely due to our acquisition of marine transportation businesses during 2008.

Changes in our revenues and costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.40 per gallon during 2008 versus $1.19 per gallon during 2007. The Henry Hub market price of natural gas averaged $9.04 per MMBtu during 2008 versus $6.86 per MMBtu during 2007. The NYMEX market price of crude oil averaged $99.73 per barrel during 2008 compared to $72.24 per barrel during 2007. See “Selected Price and Volumetric Data” included within this Item 7 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $66.2 million for 2008 compared to $13.6 million for 2007, a $52.6 million year-to-year increase. Equity in income from our investments in Energy Transfer Equity and its general partner, LE GP, increased $28.2 million year-to-year. Equity in income of our investment in Cameron Highway increased $27.6 million year-to-year due to higher transportation volumes and lower interest expense. Equity in income of our investment in Seaway increased $9.1 million year-to-year due to higher transportation fees. A non-cash impairment charge of $7.0 million associated with our investment in Nemo Gathering Company, LLC (“Nemo”) reduced equity in income for 2007. Collectively, equity in income of our other investments decreased $19.3 million year-to-year primarily due to higher repair and maintenance expenses during 2008 relative to 2007 as well as the effects of downtime and reduced volumes attributable to Hurricanes Gustav and Ike.

Operating income for 2008 was $1.77 billion compared to $1.2 billion for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $578.7 million year-to-year increase in operating income.

Interest expense increased to $608.3 million for 2008 from $487.4 million for 2007. The $120.9 million year-to-year increase in interest expense is primarily due to EPO’s issuance of senior and junior notes during 2008 and 2007 to fund capital growth projects and business combinations. Our average debt principal outstanding during 2008 was $11.27 billion compared to $8.72 billion during 2007. Other income for 2007 includes a $59.6 million gain on the sale of our interests in Mont Belvieu Storage Partners, L.P. and its general partner (collectively, “MB Storage”). See Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our sale of these equity method investments.

Provision for income taxes increased $15.2 million year-to-year primarily due to higher expenses associated with the Texas Margin Tax. The increase in expenses for the Texas Margin Tax primarily reflects a higher taxable margin in the State of Texas during 2008 relative to 2007. In addition, we recognized a $5.1 million benefit with respect to the Texas Margin Tax during 2007 due to the reorganization of certain of our entities from partnerships to limited liability companies.

As a result of items noted in the previous paragraphs, our consolidated net income increased $383.1 million year-to-year to $1.15 billion for 2008 compared to $762.0 million for 2007. Net income attributable to noncontrolling interests was $981.1 million for 2008 compared to $653.0 million for 2007. Net income attributable to Enterprise GP Holdings increased $55.0 million year-to-year to $164.0 million for 2008 compared to $109.0 million for 2007.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.33 billion for 2008 compared to $848.0 million for 2007. The $477.0 million year-to-year increase in segment gross operating margin is due to strong natural gas processing margins and petrochemical demand for NGLs as well as an increase in equity NGL production attributable to our Meeker and Pioneer natural gas processing facilities. Results for 2007 include $32.7 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds for 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $815.3 million for 2008 compared to $389.1 million for 2007. Equity NGL production increased to 108 MBPD during 2008 from 88 MBPD during 2007. The $426.2 million year-to-year increase in gross operating margin is largely due to contributions from our Meeker and Pioneer cryogenic natural gas processing facilities, which commenced commercial operations during October 2007 and February 2008, respectively. These facilities contributed $274.5 million of the year-to-year increase in gross operating margin and produced 49 MBPD of equity NGLs during 2008 compared to 23 MBPD during 2007. Collectively, gross operating margin from the remainder of this business increased $151.7 million year-to-year primarily due to improved results from our NGL marketing activities attributable to higher NGL sales margins and volumes in 2008 relative to 2007. Results for 2008 include $6.8 million of hurricane-related property damage repair expenses associated with our natural gas processing plants in south Louisiana.

Gross operating margin from our NGL pipelines and related storage business was $397.4 million for 2008 compared to $331.1 million for 2007, a $66.3 million year-to-year increase. Total NGL transportation volumes increased to 2,021 MBPD during 2008 from 1,877 MBPD during 2007. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $43.6 million year-to-year due to higher transportation volumes and an increase in the system-wide tariff. These pipeline systems contributed 116 MBPD of the year-to-year increase in NGL transportation volumes. Gross operating margin from our Mont Belvieu storage complex increased $15.5 million as a result of higher storage revenues during 2008 relative to 2007. Collectively, gross operating margin from the remainder of our NGL pipelines and storage business increased $7.2 million year-to-year attributable to higher transportation volumes on our Dixie and Lou-Tex NGL Pipeline Systems and lower maintenance and pipeline integrity expenses on our Dixie and South Louisiana Pipeline Systems. In general, the improved results from our NGL pipeline and storage assets were partially offset by downtime and reduced volumes as a result of Hurricanes Gustav and Ike during 2008. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from our NGL fractionation business was $111.2 million for 2008 compared to $95.1 million for 2007, a $16.1 million year-to-year increase. Fractionation volumes increased from 405 MBPD during 2007 to 441 MBPD during 2008. The increase in gross operating margin and fractionation volumes is primarily due to our Hobbs fractionator, which we placed into service during August 2007. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $589.9 million for 2008 compared to $493.2 million for 2007, a $96.7 million year-to-year increase. Our onshore natural gas transportation volumes were 9,612 BBtus/d during 2008 compared to 8,465 BBtus/d during 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business increased to $550.5 million for 2008 from $464.8 million for 2007. The $85.7 million year-to-year increase in gross operating margin is primarily due to (i) higher revenues from our San Juan Gathering System, (ii) higher transportation activity on our Texas Intrastate System, (iii) higher natural gas sales margins on our Acadian Gas System, and (iv) an increase in gathering volumes on our Jonah System as a result of system expansion projects. Results for 2008 include $1.3 million of hurricane-related property damage repair expenses attributable to Hurricanes Gustav and Ike.

Gross operating margin from our natural gas storage business was $39.4 million for 2008 compared to $28.4 million for 2007. The $11.0 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed additional natural gas storage caverns in operation during the third quarters of 2007 and 2008 at our Petal facility, which provided an additional 1.6 Bcf and 4.2 Bcf of subscribed capacity, respectively.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $132.2 million for 2008 compared to $109.6 million for 2007. Total onshore crude oil transportation volumes were 696 MBPD during 2008 compared to 652 MBPD during 2007. The $22.6 million year-to-year increase in segment gross operating margin is primarily due to an increase in crude oil transportation volumes and fees during 2008 relative to 2007. Completion of system expansions in south and west Texas contributed 42 MBPD of the year-to-year increase in crude oil transportation volumes. Average transportation fees on the pipeline system owned by Seaway were higher during 2008 compared to 2007 as a result of an increase in volumes transported on a spot basis and higher long-haul volumes, both of which are subject to higher tariffs.

Offshore Pipelines & Services. Gross operating margin from this business segment was $187.0 million for 2008 compared to $171.6 million for 2007, a $15.4 million year-to-year increase. Results for 2008 include $0.2 million of proceeds from business interruption insurance claims compared to $3.4 million of proceeds during 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance.

Gross operating margin from our offshore platform services business was $144.8 million for 2008 compared to $111.7 million for 2007, a $33.1 million year-to-year increase. Our Independence Hub platform, which was completed in March 2007, provided a $49.5 million year-to-year increase in gross operating margin. Gross operating margin increased year-to-year despite the platform being shut-in for 66 days during the second quarter of 2008 due to a leak on the Independence Trail export pipeline. While the Independence Hub platform did not earn volumetric fees during the period of suspended operations, the platform continued to earn its fixed demand revenues of approximately $4.6 million per month. Gross operating margin from the remainder of this business decreased $16.4 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike and upstream supply disruptions. Results for our offshore platform services business include $5.0 million of hurricane-related property damage repair expenses in 2008. Our net platform natural gas processing volumes increased to 632 MMcf/d during 2008 compared to 494 MMcf/d during 2007.

Gross operating margin from our offshore crude oil pipeline business was $35.1 million for 2008 versus $21.1 million for 2007, a $14.0 million year-to-year increase. Gross operating margin increased $27.6 million year-to-year due to increased equity in income of Cameron Highway, which benefited from higher crude oil transportation volumes and no interest expense in 2008 relative to 2007. Net to our ownership interest, crude oil transportation volumes on the Cameron Highway Oil Pipeline System were 80 MBPD in 2008 compared to 44 MBPD in 2007. Gross operating margin from the remainder of this business decreased $13.6 million year-to-year due to the effects of Hurricanes Gustav and Ike, which include (i) downtime resulting from damage sustained by our pipelines as well as downstream assets owned by third-parties and (ii) reduced volumes available to our pipelines as a result of upstream supply disruptions. Results for our offshore crude oil pipeline business include $2.3 million of hurricane-related property damage repair expenses in 2008. Total offshore crude oil transportation volumes were 169 MBPD during 2008 versus 163 MBPD during 2007.

Gross operating margin from our offshore natural gas pipeline business was $6.9 million for 2008 compared to $35.4 million for 2007, a $28.5 million year-to-year decrease. Offshore natural gas transportation volumes were 1,408 BBtus/d during 2008 versus 1,641 BBtus/d during 2007. Gross operating margin from our Independence Trail pipeline, which first received production in July 2007, increased $28.4 million year-to-year on a 241 BBtus/d increase in transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $56.9 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike. Results for 2008 include $29.9 million of hurricane-related property damage repair expenses.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $374.9 million for 2008 compared to $342.0 million for 2007.

Gross operating margin from propylene fractionation and related activities was $87.2 million for 2008 compared to $66.3 million for 2007. The $20.9 million year-to-year increase in gross operating margin is largely due to higher propylene sales margins during 2008 relative to 2007. Results for our propylene fractionation and related pipeline business for 2008 include $0.8 million of hurricane-related property damage repair expenses.

Gross operating margin from butane isomerization was $95.9 million for 2008 compared to $91.4 million for 2007. The $4.5 million year-to-year increase in gross operating margin is primarily due to strong demand for high-purity isobutane and increased by-product sales revenues as a result of higher NGL prices during 2008 relative to 2007. Butane isomerization volumes decreased to 86 MBPD during 2008 compared to 90 MBPD during 2007 due to production interruptions resulting from Hurricane Ike and operational issues at our octane enhancement facility during 2008. Gross operating margin from octane enhancement was a loss of $11.3 million for 2008 compared to $18.3 million of earnings for 2007. The $29.6 million year-to-year decrease in gross operating margin is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during 2008 and the effects of Hurricane Ike.

Gross operating margin from refined products pipelines and related activities was $132.9 million for 2008 compared to $162.7 million for 2007. The $29.8 million year-to-year decrease in gross operating margin is primarily due to higher expenses on our Products Pipeline System during 2008 relative to 2007 for storage tank and pipeline maintenance and the effects of lower transportation volumes during 2008. Transportation volumes on our refined products pipelines decreased to 702 MBPD during 2008 from 768 MBPD during 2007 due in part to the effects of Hurricanes Gustav and Ike. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from marine transportation and other services was $70.2 million for 2008 compared to $3.3 million for 2007. The $66.9 million year-to-year increase in gross operating margin is primarily attributable to the marine transportation businesses we acquired during 2008 from Cenac and Horizon. At December 31, 2008, our fleet of marine vessels consisted of 51 tow boats and 113 barges. The utilization of our marine services fleet averaged 93% during 2008.

Other Investments. Gross operating margin from this business segment was $31.3 million for 2008 compared to $3.1 million for 2007. Total segment gross operating margin increased $28.2 million year-to-year primarily as a result of our acquisition of interests in Energy Transfer Equity and LE GP in May 2007. In May 2007, the Parent Company paid $1.65 billion to acquire 38,976,090 common units of Energy Transfer Equity and approximately 34.9% of the membership interests of LE GP.

Before the amortization of excess cost amounts, our equity income from Energy Transfer Equity and LE GP was a collective $65.6 million for 2008 versus $29.8 million for 2007. Our equity income from these investments was reduced by $34.3 million and $26.7 million of excess cost amortization during 2008 and 2007, respectively. For additional information regarding our investments in Energy Transfer Equity and LE GP, see Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Liquidity and Capital Resources

On a consolidated basis, our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business combinations and distributions to partners and noncontrolling interest holders. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination), including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners and noncontrolling interest holders primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2009, we had $55.3 million of unrestricted cash on hand and approximately $1.73 billion of available credit under our revolving credit facilities, which includes the available borrowing capacity of our consolidated subsidiaries such as Enterprise Products Partners and Duncan Energy Partners. We had approximately $12.4 billion in principal outstanding under consolidated debt agreements at December 31, 2009. In total, our consolidated liquidity at December 31, 2009 was approximately $1.78 billion.

Registration Statements

Enterprise Products Partners may issue equity or debt securities to assist in meeting its liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. The Parent Company and Enterprise Products Partners each have a universal shelf registration statement on file with the SEC that would allow them to issue an unlimited amount of debt and equity securities for general partnership purposes. In addition, Duncan Energy Partners has a universal shelf registration statement on file with the SEC that allows it to issue up to $1 billion of debt and equity securities.

As of December 31, 2009, the Parent Company had not issued any securities under its registration statement. The following tables present information regarding equity and debt offerings made under Enterprise Products Partners' universal shelf registration statement since January 1, 2009 through the date of this filing. In addition, an exchange offer made in connection with the TEPPCO Merger for certain TEPPCO notes was completed under a Form S-4 registration statement in October 2009. Dollar amounts presented in the tables are in millions, except offering price amounts.

Underwritten Equity Offering	Number of Common Units Issued	Offering Price	Net Cash Proceeds (1)
January 2009 underwritten offering	10,590,000	$ 22.20	$ 225.6
September 2009 underwritten offering	8,337,500	28.00	226.4
January 2010 underwritten offering	10,925,000	32.42	343.1
Total	29,852,500		$ 795.1

(1) Net cash proceeds from these equity offerings were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Note Series	Issued	Principal Amount
Senior Notes P (1)	June 2009	$ 500.0
Senior Notes Q & R (2)	October 2009	1,100.0
Senior Notes S - W (3)	October 2009	1,659.9
Junior Subordinated Notes C (3)	October 2009	285.8
Total		$ 3,545.7

(1) Net proceeds from this senior note offering were used to repay a $200.0 million term loan, temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.
(2) Net proceeds from these senior note offerings were used to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.
(3) In connection with the TEPPCO Merger, substantially all of TEPPCO's notes were exchanged for a corresponding series of new EPO notes. The EPO notes issued in the exchange were recorded at the same carrying value as the TEPPCO notes being replaced. These notes were issued under a Form S-4 registration statement.

In 2009, Duncan Energy Partners completed an offering of 8,943,400 of its common units, which generated net cash proceeds of approximately $137.4 million. Duncan Energy Partners used the aggregate net cash proceeds from this offering to repurchase an equal number of its common units that were beneficially owned by EPO. Duncan Energy Partners subsequently cancelled the common units it repurchased from EPO. At December 31, 2009, Duncan Energy Partners can issue approximately $856.4 million of additional equity or debt securities under its registration statement.

Enterprise Products Partners has filed registration statements with the SEC authorizing the issuance of up to an aggregate 40,000,000 common units in connection with its distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of Enterprise Products Partners' common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of Enterprise Products Partners. During the year ended December 31, 2009, Enterprise Products Partners issued 11,909,083 common units in connection with its DRIP, which generated proceeds of $286.2 million from plan participants. Affiliates of EPCO reinvested $246.3 million in connection with the DRIP during the year ended December 31, 2009.

In addition, Enterprise Products Partners has a registration statement on file related to its employee unit purchase plan, under which it can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase Enterprise Products Partners' common units at a 10% discount through payroll deductions. During the year ended December 31, 2009, Enterprise Products Partners issued 180,837 common units to employees under this plan, which generated proceeds of $4.6 million.

For information regarding our public debt obligations or partnership equity, see Notes 12 and 13, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Letter of Credit Facilities

At December 31, 2009, EPO had outstanding a $50.0 million letter of credit related to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities.

Credit Ratings

The Parent Company's credit facilities are rated Ba2, BB- and BB by Moody's, Standard & Poor's and Fitch Ratings, respectively. Recently, there has been limited access to the institutional leveraged loan market for companies with similar ratings to those of the Parent Company. At this time, we are unable to estimate when these market conditions will improve.

At March 1, 2010, the investment-grade credit ratings of EPO's senior unsecured debt securities remain unchanged from December 31, 2009 at Baa3 by Moody's Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor's. Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Based on the characteristics of the $1.53 billion of fixed/floating unsecured junior subordinated notes, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

A downgrade of Enterprise Products Partners' credit ratings could result in it being required to post financial collateral up to the amount of its guaranty of indebtedness of its Centennial joint venture, which was $60.0 million at December 31, 2009. Furthermore, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral, which may be substantial, if our credit were to be downgraded below investment grade.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For Year Ended December 31,		
	2009	**2008**	**2007**
Net cash flows provided by operating activities	$ 2,410.3	$ 1,566.4	$ 1,936.8
Cash used in investing activities	1,547.7	3,246.9	4,541.1
Cash provided by (used in) financing activities	(863.9)	1,695.9	2,622.5

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstock in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see “Risk Factors” under Item 1A of this annual report.

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) other non-cash amounts such as depreciation, amortization, operating lease expenses paid by EPCO, changes in the fair market value of derivative instruments and equity in earnings from unconsolidated affiliates (net cash flows provided by operating activities reflect the actual cash distributions we receive from such investees), and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.

In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

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

Comparison of 2009 with 2008

Operating Activities. The $843.9 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates, cash payments for interest and cash payments for income taxes) increased $888.7 million year-to-year. The increase in operating cash flow is generally due to increased profitability and the timing of related cash receipts and disbursements. The total year-to-year increase also reflects a $68.9 million increase in operating cash proceeds we received from insurance claims related to certain named storms. For information regarding cash proceeds from business interruption and property damage claims, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Cash distributions received from unconsolidated affiliates increased $12.1 million year-to-year, including a $6.2 million increase in distributions received from Energy Transfer Equity.

§ Cash payments for interest increased $56.9 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt principal outstanding for 2009 was $13.02 billion compared to $11.27 billion for 2008.

§ Cash payments for income taxes increased $22.7 million year-to-year primarily due to higher payments made for the Texas Margin tax and a taxable gain incurred in 2009 arising from Dixie's sale of certain assets.

Investing Activities. The $1.7 billion decrease in cash used for investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $945.9 million year-to-year. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

§ Cash used for business combinations decreased $446.2 million year-to-year. Our 2009 business combinations primarily consisted of the acquisition of certain rail and truck terminal facilities located in Mont Belvieu, Texas, a pipeline system in Texas, and the acquisition of tow boats and tank barges primarily based in Miami, Florida, with additional assets located in Mobile, Alabama and Houston, Texas. In 2008, our most significant business combinations consisted of our acquisition of marine transportation businesses. In addition, during 2008 we acquired 100% of the membership interest in Great Divide Gathering LLC ("Great Divide") and additional interests in consolidated subsidiaries. For additional information regarding our business combinations, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Restricted cash related to our hedging activities decreased $140.2 million (a cash inflow) during 2009 primarily due to the reduction of margin requirements related to derivative instruments we utilized. For 2008, restricted cash related to our hedging activities increased $132.8 million (a cash outflow). See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our interest rate and commodity risk hedging portfolios.

Financing Activities. Cash used in financing activities was $863.9 million for 2009 compared to cash provided by financing activities of $1,695.9 million in 2008. The $2.56 billion change in financing activities was primarily due to the following:

§ Net repayments under our consolidated debt agreements of $272.5 million in 2009 compared to net borrowings under our consolidated debt agreements of $2.74 billion in 2008. During 2008, EPO and TEPPCO issued a combined $2.6 billion in principal amount of senior notes. For information regarding our consolidated debt obligations see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Cash distributions paid to our partners increased $53.6 million year-to-year primarily due to increases in our quarterly distribution rates.

§ Distributions paid to noncontrolling interests increased $140.0 million year-to-year primarily due to increases in the number of units outstanding and quarterly distribution rates of Enterprise Products Partners, Duncan Energy Partners and TEPPCO (prior to the TEPPCO Merger).

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§ Contributions from noncontrolling interests increased $567.8 million year-to-year primarily due to net cash proceeds that Enterprise Products Partners and Duncan Energy Partners received from 2009 common unit offerings. For additional information related to the common unit offerings of Enterprise Products Partners and Duncan Energy Partners, see "Registration Statements" included within this Item 7.

Comparison of 2008 with 2007

Operating Activities. The $370.4 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates and cash payments for interest) decreased $108.2 million year-to-year. Although our gross operating margin increased year-to-year (see "Results of Operations" within this Item 7), the reduction in operating cash flow is generally due to the timing of related cash receipts and disbursements. The $108.2 million total year-to-year decrease also reflects a $127.3 million decrease in cash proceeds we received from insurance claims related to certain named storms. For information regarding cash proceeds from business interruption and property damage claims, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Cash distributions received from unconsolidated affiliates increased $40.3 million year-to-year primarily due to increased distributions from Energy Transfer Equity and LE GP. We acquired interests in Energy Transfer Equity and LE GP in May 2007 and received our first cash distributions from such entities in July 2007. In addition, the sale of TEPPCO's ownership interest in MB Storage in the first quarter of 2007 resulted in a decrease in distributions year-to-year. We received $10.4 million of distributions from MB Storage in 2007. The decrease in distributions received from unconsolidated affiliates related to MB Storage was partially offset by increased distributions from Cameron Highway.

§ Cash payments for interest increased $302.5 million year-to-year primarily due to increased borrowings to finance our capital spending program, including borrowings made in May 2007 to acquire interests in Energy Transfer Equity and LE GP. Our average debt principal outstanding for 2008 was $11.27 billion compared to $8.72 billion for 2007.

Investing Activities. The $1.29 billion decrease in cash used for investing activities was primarily due to the following:

§ Cash outlays for investments in unconsolidated affiliates decreased by $1.86 billion year-to-year primarily due to the $1.65 billion we paid to acquire interests in Energy Transfer Equity and LE GP in May 2007. Other expenditures for 2007 include the $216.5 million we contributed to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt. Expenditures for 2008 include (i) $22.5 million in contributions to White River Hub, (ii) $11.1 million in contributions to Centennial and (iii) $36.0 million to acquire a 49% interest in Skelly-Belvieu.

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $179.0 million year-to-year. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

§ Proceeds from the sale of assets and related transactions decreased $146.8 million year-to-year primarily due to the sale of certain equity interests and related storage assets located in Mont Belvieu, Texas during 2007.

§ Cash used for business combinations increased $517.6 million year-to-year, primarily due to approximately $346.0 million in business combinations related to our marine transportation businesses. In addition, during 2008 we acquired 100% of the membership interest in Great Divide and additional interests in consolidated subsidiaries.

§ An $85.5 million increase in restricted cash (a cash outflow) due to margin requirements related to our hedging activities. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our interest rate and commodity risk hedging portfolios.

Financing Activities. The $926.6 million decrease in cash provided by financing activities was primarily due to the following:

§ Net proceeds from the issuance of our Units decreased $739.4 million year-to-year due to the July 2007 private placement of 20,134,220 Units to third-party investors.

Net borrowings under our consolidated debt agreements decreased $24.1 million year-to-year. During 2008, EPO and TEPPCO issued a combined $2.6 billion in principal amount of senior notes. In May 2007, the Parent Company borrowed $1.8 billion to acquire equity interests in Energy Transfer Equity and LE GP and to repay amounts outstanding under a prior credit facility. The Parent Company used proceeds from its private placement of Units in July 2007 to repay certain principal amounts outstanding under an interim credit facility and related accrued interest. For information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Contributions from noncontrolling interests increased $73.7 million year-to-year primarily due to TEPPCO's issuance of 9.2 million of its units in September 2008, which generated net cash proceeds of $257.0 million, offset by the initial public offering of Duncan Energy Partners in February 2007, which generated proceeds of $290.5 million. In addition, proceeds generated by Enterprise Products Partners' DRIP and employee unit purchase plan increased $80.5 million year-to-year.

§ Cash distributions paid to our partners increased $54.1 million year-to-year primarily due to increases in our quarterly distribution rates.

- § Distributions paid to noncontrolling interests increased $108.2 million year-to-year primarily due to increases in the quarterly distribution rates of Enterprise Products Partners, Duncan Energy Partners and TEPPCO, along with an increase in TEPPCO's and Enterprise Products Partners' number of units outstanding.

- § The early termination and settlement of interest rate hedging derivative instruments during 2008 resulted in net cash payments of $66.5 million compared to net cash receipts of $49.1 million during the same period in 2007, which resulted in a $115.6 million decrease in financing cash flows between years.

Cash Flow Analysis – Parent Company

The primary sources of cash flow for the Parent Company are its investments in limited and general partner interests of publicly traded limited partnerships. The cash distributions the Parent Company receives from its investments in Enterprise Products Partners and Energy Transfer Equity and their respective general partners are exposed to certain risks inherent in the underlying business of each entity. For information regarding such risks, see Item 1A of this annual report.

The Parent Company's primary cash requirements are for general and administrative costs, debt service costs, investments and distributions to its partners. The Parent Company expects to fund its short-term cash requirements for its expenses such as general and administrative costs using cash flows from operations. Debt service requirements are expected to be funded by cash flows from operations and/or debt refinancing arrangements. The Parent Company expects to fund its cash distributions paid to partners primarily with cash flows from operations.

The following table summarizes key components of the Parent Company's cash flow information for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2009	2008	2007
Net cash provided by operating activities (1)	$ 298.6	$ 234.7	$ 184.6
Cash used in investing activities (2)	38.3	7.7	1,650.8
Cash provided by (used in) financing activities (3)	(262.2)	(226.2)	1,467.1
Cash and cash equivalents, end of period	0.6	2.5	1.7

(1) Primarily represents distributions received from unconsolidated affiliates less cash payments for interest and general and administrative costs. See following table for detailed information regarding distributions from unconsolidated affiliates.

(2) Primarily represents investments in unconsolidated affiliates. The amount for 2007 includes the $1.65 billion paid to acquire interests in Energy Transfer Equity and LE GP in May 2007.

(3) Primarily represents net cash proceeds from borrowings and equity offerings offset by repayments of debt principal and distribution payments to unitholders. The amount presented for 2007 includes $739.4 million in net proceeds from an equity offering in July 2007.

The following table presents cash distributions received from unconsolidated affiliates and cash distributions paid by the Parent Company for the periods indicated (dollars in millions):

	For Year Ended December 31, 2009	2008	2007
Cash distributions from investees: (1)			
Investment in Enterprise Products Partners and EPGP:			
From common units of Enterprise Products Partners	$ 33.5	$ 27.5	$ 25.8
From 2% general partner interest in Enterprise Products Partners	21.8	18.2	16.9
From general partner IDRs in distributions of Enterprise Products Partners	161.3	123.9	104.7
Investment in TEPPCO and TEPPCO GP:			
From 4,400,000 common units of TEPPCO	9.6	12.5	12.1
From 2% general partner interest in TEPPCO	4.7	5.6	5.0
From general partner IDRs in distributions of TEPPCO	41.8	49.3	43.2
Investment in Energy Transfer Equity and LE GP: (2)			
From 38,976,090 common units of Energy Transfer Equity	82.0	76.0	29.7
From member interest in LE GP	0.7	0.5	0.2
Total cash distributions received	$ 355.4	$ 313.5	$ 237.6
Distributions by the Parent Company:			
EPCO and affiliates	$ 205.7	$ 158.9	$ 125.9
Public	61.0	54.2	33.1
General partner interest	*	*	*
Total distributions by the Parent Company	$ 266.7	$ 213.1	$ 159.0
Distributions paid to affiliates of EPCO that were the former owners of the TEPPCO and TEPPCO GP interests contributed to the Parent Company in May 2007 (3)	$ --	$ --	$ 29.8

* Amount is negligible.
(1) Represents cash distributions received during each reporting period.
(2) The Parent Company received its first cash distribution from Energy Transfer Equity and LE GP in July 2007.
(3) Represents cash distributions paid to affiliates of EPCO that were former owners of these partnership and membership interests prior to the contribution of such interests to the Parent Company in May 2007.

For additional financial information pertaining to the Parent Company, see Note 22 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The amount of cash distributions the Parent Company is able to pay its unitholders may fluctuate based on the level of distributions it receives from Enterprise Products Partners, Energy Transfer Equity and their respective general partners. For example, if EPO is not able to satisfy certain financial covenants in accordance with its credit agreements, Enterprise Products Partners would be restricted from making quarterly cash distributions to its partners. Factors such as capital contributions, debt service requirements, general, administrative and other expenses, reserves for future distributions and other cash reserves established by the board of directors of EPE Holdings may affect the distributions the Parent Company makes to its unitholders. The Parent Company's credit agreements contain covenants requiring it to maintain certain financial ratios. Also, the Parent Company is prohibited from making any distribution to its unitholders if such distribution would cause an event of default or otherwise violate a covenant under its credit agreements.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. Enterprise Products Partners believes that it is positioned to continue to grow its system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins in the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale, Eagle Ford Shale, Marcellus Shale and deepwater Gulf of Mexico producing regions.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending by activity for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2009	**2008**	**2007**
Capital spending for business combinations:			
Great Divide Gathering System acquisition	$ --	$ 125.2	$ --
South Monco Pipeline System acquisition	0.8	--	35.0
Cenac and Horizon acquisition	--	345.7	--
Other business combinations	106.5	82.6	0.9
Total	107.3	553.5	35.9
Capital spending for property, plant and equipment, net: (1)			
Growth capital projects (2)	1,373.9	2,249.5	2,449.7
Sustaining capital projects (3)	192.6	262.9	241.7
Total	1,566.5	2,512.4	2,691.4
Capital spending for intangible assets:			
Acquisition of intangible assets	1.4	5.8	14.5
Capital spending attributable to unconsolidated affiliates:			
Investments in unconsolidated affiliates (4)	19.6	64.7	1,921.1
Total capital spending	$ 1,694.8	$ 3,136.4	$ 4,662.9

(1) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $17.8 million, $27.2 million and $57.7 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(2) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.

(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

(4) Amount for 2007 includes $1.65 billion paid to acquire interests in Energy Transfer Equity and LE GP.

Based on information currently available, we estimate our consolidated capital spending for 2010 will approximate $1.75 billion, which includes estimated expenditures of $1.5 billion for growth capital projects and acquisitions and $250.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2009, we had approximately $497.5 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction at our Mont Belvieu complex and our Barnett Shale, Haynesville Shale and Piceance Basin natural gas pipeline projects.

Pipeline Integrity Costs

Our NGL, crude oil, refined products, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the DOT. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

In April 2002, a subsidiary of ours acquired several midstream energy assets located in Texas and New Mexico from El Paso Corporation ("El Paso"). These assets included the Texas Intrastate System and the Carlsbad Gathering Systems. With respect to such assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007, we recovered $31.1 million from El Paso related to our 2006 expenditures. During 2007, we received a final amount of $5.4 million from El Paso related to this indemnity.

The following table summarizes our pipeline integrity costs, net of indemnity payments from El Paso, for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2009	2008	2007
Expensed	$ 44.9	$ 55.4	$ 51.9
Capitalized	37.7	86.2	78.9
Total	$ 82.6	$ 141.6	$ 130.8

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $116.3 million in 2010.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

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

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively.

Examples of such circumstances include:

§ changes in laws and regulations that limit the estimated economic life of an asset;

§ changes in technology that render an asset obsolete;

§ changes in expected salvage values; or

§ changes in the forecast life of applicable resource basins, if any.

At December 31, 2009 and 2008, the net book value of our property, plant and equipment was $17.69 billion and $16.73 billion, respectively. We recorded $678.1 million, $595.9 million and $515.7 million in depreciation expense for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil or refined products. Long-lived assets with carrying values that are not expected to be recovered through forecast future cash flows are written down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

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. Equity method investments with carrying values that are not expected to be recovered through expected future cash flows are written down to their estimated fair values. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

During 2009, we recognized non-cash asset impairment charges related to property, plant and equipment of $29.4 million, which is reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2008 or 2007.

During 2007, we evaluated our equity method investment in Nemo for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of equity in earnings from unconsolidated affiliates for the year ended December 31, 2007. During 2009 and 2008, there were no such impairment charges.

For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see Notes 6 and 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

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

Our customer relationship intangible assets primarily represent customer bases we acquired in connection with business combinations. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement or the natural gas transportation contracts of our Val Verde and Jonah systems. 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., fractionation facility, pipeline or other asset);

§ 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. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's unamortized cost is not recoverable due to impairment; we would be required to reduce the asset's carrying value to fair value. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2009 and 2008, the carrying value of our intangible asset portfolio was $1.06 billion and $1.18 billion, respectively. We recorded $119.9 million, $130.0 million and $125.2 million in amortization expense associated with our intangible assets for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our intangible assets, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill for impairment at the end 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 classified 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 the goodwill to its implied fair value. Based on our most recent goodwill impairment testing, each reporting unit's fair value was substantially in excess (a minimum of 10%) of its carrying value.

At December 31, 2009 and 2008, the carrying value of our goodwill was $2.02 billion. We recorded goodwill impairment charges of $1.3 million during 2009. No such impairment charges were recorded in 2008 or 2007. For additional information regarding our goodwill, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met:

- § persuasive evidence of an exchange arrangement exists;

- § delivery has occurred or services have been rendered;

- § the buyer's price is fixed or determinable; and

- § collectability is reasonably assured.

We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). For additional information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

Reserves for Environmental Matters

Our business activities are subject to various federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

At December 31, 2009 and 2008, we had a liability for environmental remediation of $16.7 million and $22.3 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We have recorded our best estimate of the cost of remediation activities. See Notes 2 and 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding environmental matters.

Natural Gas Imbalances

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

The following table presents our natural gas imbalance receivables/payables at the dates indicated:

	December 31,	
	2009	2008
Natural gas imbalance receivables (1)	$ 24.1	$ 63.4
Natural gas imbalance payables (2)	19.0	50.8

(1) Reflected as a component of “Accounts and notes receivable – trade” on our Consolidated Balance Sheets included under Item 8 of this annual report.
(2) Reflected as a component of “Accrued product payables” on our Consolidated Balance Sheets included under Item 8 of this annual report.

Other Items

Insurance Matters

We participate as a named insured in EPCO’s insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage. For additional information regarding insurance matters, see Note 19 of the Notes Consolidated Financial Statements included under Item 8 of this annual report.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2009 (dollars in millions).

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long-term debt (1)	$ 12,378.5	$ 562.5	$ 2,368.3	$ 3,157.5	$ 6,290.2
Estimated cash payments for interest (2)	12,520.3	706.4	1,253.1	985.6	9,575.2
Operating lease obligations (3)	343.9	37.6	68.0	48.8	189.5
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	5,697.6	1,308.9	1,381.8	959.3	2,047.6
NGLs	2,943.0	997.0	669.1	659.4	617.5
Crude oil	237.3	237.3	--	--	--
Petrochemicals & refined products	2,642.2	1,486.6	824.5	186.3	144.8
Other	114.1	21.2	24.1	22.8	46.0
Underlying major volume commitments:					
Natural gas (in BBtus)	969,180	221,530	230,450	165,008	352,192
NGLs (in MBbls)	49,300	19,048	10,496	10,316	9,440
Crude oil (in MBbls)	2,985	2,985	--	--	--
Petrochemicals & refined products (in MBbls)	35,034	19,523	11,122	2,469	1,920
Service payment commitments (5)	575.6	72.0	113.7	110.1	279.8
Capital expenditure commitments (6)	497.5	497.5	--	--	--
Other long-term liabilities (7)	159.7	--	34.7	15.2	109.8
Total	$ 38,109.7	$ 5,927.0	$ 6,737.3	$ 6,145.0	$ 19,300.4

(1) Represents our scheduled future maturities of consolidated debt principal obligations. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Our estimated cash payments for interest are based on the principal amount of consolidated debt obligations outstanding at December 31, 2009. With respect to variable-rate debt obligations, we applied the weighted-average interest rate paid during 2009 associated with such debt. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for the weighted-average variable interest rates charged in 2009 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2009. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding these derivative instruments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $550.0 million Junior Subordinated Notes A (due August 2066), $682.7 million Junior Subordinated Notes B (due January 2068), $300.0 million Junior Subordinated Notes C (due June 2067) and TEPPCO Junior Subordinated Notes (due June 2067). Our estimated cash payments for interest assume that these subordinated notes are not called prior to their respective maturity dates.

(3) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO and (iii) land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services under the terms of each agreement at December 31, 2009. The estimated payment obligations are based on contractual prices in effect at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

(5) Represents future payment commitments for services provided by third-parties.

(6) Represents short-term unconditional payment obligations relating to our capital projects, including our share of those of our unconsolidated affiliates, for services rendered or products purchased.

(7) As reflected on our Consolidated Balance Sheet at December 31, 2009, other long-term liabilities primarily represent noncurrent portions of asset retirement obligations, reserves for environmental remediation costs, accrued pipeline transportation deficiency fees, deferred revenues and the Centennial guarantee.

For additional information regarding our significant contractual obligations involving operating leases and purchase obligations, see Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Off-Balance Sheet Arrangements

Except for the following information regarding debt obligations of certain unconsolidated affiliates, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources. The following information summarizes the significant terms of such unconsolidated debt obligations.

Poseidon. At December 31, 2009, Poseidon's debt obligations consisted of $92.0 million outstanding under its $150.0 million variable-rate revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets. Poseidon expects to fund the repayment of its revolving credit facility (including accrued interest) with a variety of sources (either separately or in combination) including operating cash flows, refinancing agreements or cash contributions from its joint venture partners.

Evangeline. At December 31, 2009, Evangeline's debt obligations consisted of (i) $3.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable due in 2011. Evangeline expects to fund the repayment of its debt obligations (including accrued interest) using operating cash flows.

Centennial. At December 31, 2009, Centennial's debt obligations consisted of $120.0 million borrowed under a master shelf loan agreement through two private placements, with interest rate ranging from 7.99% to 8.09%. 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. Specifically, we and our joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial were to default on its debt obligations, our estimated payment obligation would be $60.0 million based on amounts outstanding at December 31, 2009.

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report as well as Item 13 of this annual report.

Non-GAAP Reconciliations

The following table presents a reconciliation of our non-GAAP measure of total segment gross operating margin to GAAP operating income and income before provision for income taxes for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2009	2008	2007
Total segment gross operating margin	$ 2,880.9	$ 2,640.3	$ 1,967.5
Adjustments to reconcile total segment gross operating margin			
to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(809.3)	(725.4)	(647.9)
Impairment charges in operating costs and expenses	(33.5)	--	--
Operating lease expenses paid by EPCO	(0.7)	(2.0)	(2.1)
Gain from asset sales and related transactions in operating costs and expenses	--	4.0	7.8
General and administrative costs	(182.8)	(144.8)	(131.9)
Operating income	1,854.6	1,772.1	1,193.4
Other expense, net	(689.0)	(596.0)	(415.6)
Income before provision for income taxes	$ 1,165.6	$ 1,176.1	$ 777.8

Recent Accounting Developments

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

§ Fair Value Measurements; and

§ Consolidation of Variable Interest Entities.

For additional information regarding recent accounting developments, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our derivative instruments outstanding and related hedging activities, including associated fair value measurements. See Note 13 of the Notes to Consolidated Financial Statements for information regarding the impact of derivative instruments on accumulated other comprehensive loss as reported on our Consolidated Balance Sheets.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following tables show the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolios at the dates presented (dollars in millions):

Parent Company

		Swap Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying interest rates	*Liability*	$ (26.5)	$ (17.6)	$ (16.1)
FV assuming 10% increase in underlying interest rates	*Liability*	(25.4)	(17.2)	(15.8)
FV assuming 10% decrease in underlying interest rates	*Liability*	(27.7)	(18.1)	(16.4)

Enterprise Products Partners (excluding Duncan Energy Partners)

		Swap Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying interest rates	*Asset*	$ 46.7	$ 41.3	$ 53.2
FV assuming 10% increase in underlying interest rates	*Asset*	42.4	35.0	47.9
FV assuming 10% decrease in underlying interest rates	*Asset*	51.1	47.8	58.5

Duncan Energy Partners		**Swap Fair Value at**		
Scenario	**Resulting Classification**	**December 31, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying interest rates	*Liability*	$ (9.8)	$ (5.5)	$ (5.7)
FV assuming 10% increase in underlying interest rates	*Liability*	(9.4)	(5.5)	(5.7)
FV assuming 10% decrease in underlying interest rates	*Liability*	(10.2)	(5.6)	(5.7)

The following table shows the effect of hypothetical price movements on the estimated fair value of our forward starting swap portfolio at the dates presented (dollars in millions):

		Swap Fair Value at	
Scenario	**Resulting Classification**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying interest rates	*Asset*	$ 21.0	$ 13.3
FV assuming 10% increase in underlying interest rates	*Asset*	31.1	26.1
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	10.5	(0.5)

In January 2010, we entered into two additional forward starting interest rate swaps with a notional amount of $50.0 million each. In February 2010, we entered into three additional forward starting swaps with a notional amount of $50.0 million each. The period hedged by these five forward starting swaps is February 2012 through February 2022.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. We may use commodity-based derivative instruments such as forward contracts, futures, swaps and options to mitigate such risks.

We assess the risk of our commodity financial instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to these portfolios measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity derivative instruments outstanding at the date indicated within the following tables.

The following table shows the effect of hypothetical price movements on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

		Swap Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 6.5	$ (1.5)	$ (2.3)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	2.7	(7.0)	(6.3)
FV assuming 10% decrease in underlying commodity prices	*Asset*	9.9	4.1	1.8

The following table shows the effect of hypothetical price movements on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates presented (dollars in millions):

		Swap Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2008**	**December 31, 2009**	**January 31, 2010**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (102.1)	$ (9.2)	$ 21.3
FV assuming 10% increase in underlying commodity prices	*Liability*	(94.0)	(43.2)	(19.5)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(110.1)	24.8	62.0

The following table shows the effect of hypothetical price movements on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Swap Fair Value at December 31, 2008	Swap Fair Value at December 31, 2009	Swap Fair Value at January 31, 2010
FV assuming no change in underlying commodity prices	*Asset*	$ --	$ 2.0	$ 1.1
FV assuming 10% increase in underlying commodity prices	*Asset*	--	2.0	1.1
FV assuming 10% decrease in underlying commodity prices	*Asset*	--	2.1	1.1

Our predominant hedging strategy is to hedge an amount of gross margin associated with the gas processing activities. We achieve this by using physical and financial instruments to lock in the prices of NGL sales and natural gas purchases used for PTR. This program consists of:

§ the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, achieved through the use of forward physical sales and commodity derivative instruments and

§ the purchase of commodity derivative instruments with a notional amount determined by the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At December 31, 2009, this program had hedged future estimated gross margins (before plant operating expenses) of $178.9 million on 6.0 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2010. At February 22, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $344.0 million on 10.8 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2010. Our estimates of future gross margins are subject to various business risks, including unforeseen production outages or declines, counterparty risk, or similar events or developments that are outside of our control.

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate. At December 31, 2009, we had foreign currency derivative instruments outstanding with a notional amount of $4.1 million Canadian outstanding. The fair market value of this instrument was an asset of $0.2 million at December 31, 2009.

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, petrochemicals and other hydrocarbons with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see “Contractual Obligations” included under Item 7 of this annual report.

Item 8. *Financial Statements and Supplementary Data.*

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

As required by the SEC pursuant to Regulation S-X Rule 3-09, Energy Transfer Equity, L.P.’s consolidated financial statements and notes thereto have been filed as Exhibit 99.1 to this annual report.

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

None.

Item 9A. *Controls and Procedures*.

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of our general partner's chief executive officer (our principal executive officer) (the "CEO") and our general partner's chief financial officer (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 this evaluation, as of the end of the period covered by this annual report, the CEO and CFO concluded:

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

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

Changes in Internal Control over Financial Reporting

There 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 2009, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this annual report.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2009

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

Our management assessed the effectiveness of Enterprise GP Holdings' internal control over financial reporting as of December 31, 2009. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework*. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2009, Enterprise GP Holdings' internal control over financial reporting is effective based on those criteria.

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

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. That report is included within this Item 9A.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 1, 2010.

/s/ Dr. Ralph S. Cunningham
Name: Dr. Ralph S. Cunningham
Title: Chief Executive Officer of our general partner, EPE Holdings, LLC

/s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Chief Financial Officer of our general partner, EPE Holdings, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Enterprise GP Holdings L.P. and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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, 2009. Our responsibility is to express an opinion on the Company'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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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 operations, comprehensive income, cash flows, and equity as of and for the year ended December 31, 2009 of the Company and our report dated March 1, 2010 expresses an unqualified opinion on those financial statements and includes an explanatory paragraph concerning the retroactive effects of the common control acquisition of TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC by Enterprise

Products Partners L.P. on October 26, 2009 and the related change in business segments described in Notes 1 and 11.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

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

None.

PART III

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

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA under the direction of the Board of Directors (the "Board") and executive officers of EPE Holdings. For a description of the ASA, see "Relationship with EPCO and Affiliates – EPCO ASA" in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The executive officers of our general partner are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of EPE Holdings. Dan L. Duncan, through his indirect control of EPE Holdings, has the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of our general partner serves until such member's death, resignation or removal. The current employees of EPCO who served as directors of EPE Holdings during 2009 were Dan L. Duncan, Randa D. Williams, Dr. Ralph S. Cunningham, Richard H. Bachmann, Michael A. Creel, W. Randall Fowler and A. James Teague.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of our general partner maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, EPE Holdings is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to EPE Holdings. Whenever possible, EPE Holdings intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

Corporate Governance

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

A key element for strong governance is independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with EPE Holdings or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with EPE Holdings or us). Based on the foregoing, the Board has affirmatively determined that Charles E. McMahen, Edwin E. Smith, and Thurmon M. Andress are “independent” directors under the NYSE rules. In making its determination, the Board’s consideration included the fact that Mr. Andress’ grandson is an employee of EPCO. Mr. Andress’ grandson does not live with Mr. Andress and is not an executive officer of EPCO or any affiliate thereof. The amount of compensation paid to Mr. Andress’ grandson in 2009 in consideration for his services to EPCO and its affiliates did not exceed $120,000.

Code of Conduct and Ethics and Corporate Governance Guidelines

EPE Holdings has adopted a “Code of Conduct” that applies to its directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our chief executive officer, chief financial officer, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting of violations of the code (and thus accountability for adherence to the code).

Governance guidelines, together with applicable committee charters, provide the framework for effective governance. The Board has adopted the “Governance Guidelines of Enterprise GP Holdings,” which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the ACG Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise GP Holdings annually or more often as deemed necessary.

We provide investors access to current information relating to our governance procedures and principles, including the Code of Ethical Conduct for Senior Financial Officers and Managers, the Governance Guidelines of Enterprise GP Holdings and other matters, through our Internet website, www.enterprisegp.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

ACG Committee

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

The members of the ACG Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the ACG Committee shall have accounting or related financial management expertise. The members of the ACG Committee are Messrs. McMahen, Smith and Andress. Our Board has affirmatively determined that Mr. McMahen satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

The ACG Committee's duties are addressing audit and conflicts-related items and general corporate governance matters. From an audit and conflicts standpoint, the primary responsibilities of the ACG Committee include:

§ reviewing potential conflicts of interests, including related party transactions;

§ monitoring the integrity of our financial reporting process and related systems of internal control;

§ ensuring our legal and regulatory compliance and that of EPE Holdings;

§ overseeing the independence and performance of our independent public accountant;

§ approving all services performed by our independent public accountant;

§ providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board;

§ encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;

§ reviewing areas of potential significant financial risk to our businesses; and

§ approving awards granted under our long-term incentive plans.

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

Pursuant to its formal written charter, the ACG Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The ACG Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

From a governance standpoint, the primary duties and responsibilities of the ACG Committee are to recommend to the Board a set of governance principles applicable to us and review such guidelines from time to time, making any changes that the ACG Committee deems necessary. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our Internet website, www.enterprisegp.com. You may also contact our Investor Relations department at (866) 230-0745 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

On March 20, 2009, Dr. Ralph S. Cunningham, our CEO, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of March 20, 2009.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

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

Directors and Executive Officers of EPE Holdings

The following table sets forth the name, age and position of each of the directors and executive officers of EPE Holdings at March 1, 2010.

Name	Age	Position with EPE Holdings
Dan L. Duncan (1)	77	Director and Chairman
Dr. Ralph S. Cunningham (1)	69	Director, President and CEO
W. Randall Fowler (1)	53	Director, Executive Vice President and CFO
Richard H. Bachmann (1)	57	Director, Executive Vice President, Chief Legal Officer and Secretary
Randa Duncan Williams	48	Director
O. S. Andras	74	Director
Michael A. Creel	56	Director
A. James Teague	64	Director
Charles E. McMahen (2,3)	70	Director
Edwin E. Smith (2)	78	Director
Thurmon M. Andress (2)	76	Director
William Ordemann (1)	50	Executive Vice President and Chief Operating Officer
Bryan F. Bulawa (1)	40	Senior Vice President and Treasurer
Michael J. Knesek (1)	55	Senior Vice President, Controller and Principal Accounting Officer

(1) Executive officer
(2) Member of ACG Committee
(3) Chairman of ACG Committee

The following information presents a brief history of the business experience of the directors and executive officers of EPE Holdings serving as of March 1, 2010.

Dan L. Duncan. Mr. Duncan was elected Chairman and a Director of EPGP in April 1998, Chairman and a Director of the general partner (now the managing member) of EPO in December 2003, Chairman and a Director of EPE Holdings in August 2005 and Chairman and a Director of DEP GP in October 2006. Mr. Duncan served as the sole Chairman of EPCO from 1979 to December 2007. Mr. Duncan now serves as Group Co-Chairman of EPCO with his daughter, Ms. Randa Duncan Williams, who is also a Director of EPE Holdings. In December 2009, Mr. Duncan was appointed as a Director of LE GP, the general partner of Energy Transfer Equity. He also serves as an Honorary Trustee of the Board of Trustees of the Texas Heart Institute at Saint Luke's Episcopal Hospital and on the Board of Trustees of the Baylor College of Medicine.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of EPGP in February 2006, having previously served as a Director of EPGP from 1998 until March 2005. In addition to these duties, Dr. Cunningham served as Group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007 and Interim President and Interim CEO from June 2007 to August 2007. In August 2007, Dr. Cunningham was elected a Director of DEP GP and a Director, the President and CEO of EPE Holdings. He served as Chairman and a Director of TEPPCO GP from March 2005 until November 2005.

Dr. Cunningham was elected a Group Vice Chairman of EPCO in December 2007, having previously served as a Director of EPCO from 1987 to 1997. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), LE GP, the general partner of Energy Transfer Equity (a publicly traded energy services partnership) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company). In addition, Dr. Cunningham serves as a Director and the Chairman of the Safety, Health and Responsibility Committee of Cenovus Energy Inc. (a Canadian publicly traded oil company). Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he served as President and CEO since 1995.

W. Randall Fowler. Mr. Fowler was elected Executive Vice President and CFO of EPGP, EPE Holdings and DEP GP in August 2007. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler has also served as a Director of EPGP and of EPE Holdings since February 2006 and of DEP GP since September 2006. Mr. Fowler also served as Senior Vice President and CFO of EPE Holdings from August 2005 to August 2007.

Mr. Fowler was elected President and CEO of EPCO in December 2007. Prior to these elections, he served as CFO of EPCO from April 2005 to December 2007. Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise Products Partners as Director of Investor Relations in January 1999. Mr. Fowler also serves as Chairman of the Board of the National Association of Publicly Traded Partnerships.

Richard H. Bachmann. Mr. Bachmann was elected an Executive Vice President and the Chief Legal Officer of EPGP in February 1999, was elected Secretary of EPGP in November 1999 and was elected a Director of EPGP in February 2006. He previously served as a Director of EPGP from June 2000 to January 2004. Mr. Bachmann has served as an Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings since April 2005.

Mr. Bachmann was elected as the Chief Legal Officer and Secretary of EPCO in May 1999 and as a Group Vice Chairman of EPCO in December 2007. In October 2006, Mr. Bachmann was elected President, CEO and a Director of DEP GP. Mr. Bachmann was elected a Director of EPE Holdings in February 2006. Since January 1999, Mr. Bachmann has served as a Director of EPCO. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation and Nominating and Governance Committees of Constellation Energy Partners LLC and as the chairman of its Conflicts Committee.

Randa Duncan Williams. Ms. Williams was elected a Director of EPE Holdings in May 2007. Ms. Williams is a daughter of Dan L. Duncan and a Director of EPCO. Prior to joining EPCO in 1994, Ms. Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. She currently serves on the boards of directors of Encore Bancshares and Encore Bank and also serves on the board of trustees for numerous charitable organizations.

O. S. Andras. Mr. Andras was elected a Director of EPE Holdings in February 2007, having served as a Director of EPGP from April 1998 to February 2006. Mr. Andras served as the Vice Chairman of EPGP from September 2004 to July 2005 and as the CEO of EPGP from April 1998 to February 2005. Mr. Andras served as President of EPGP from April 1998 until September 2004. He served as President and CEO of EPCO from 1996 to February 2001.

Michael A. Creel. Mr. Creel was elected President and CEO of EPGP in August 2007. From June 2000 to August 2007, Mr. Creel served as CFO of EPGP and an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a Certified Public Accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

In December 2007, Mr. Creel was elected Group Vice Chairman and CFO of EPCO. Prior to these elections in EPCO, Mr. Creel served as Chief Operating Officer from April 2005 to December 2007 and CFO from June 2000 to April 2005 for EPCO. He also serves as a Director of EPE Holdings, DEP GP and EPGP since October 2009, October 2006 and February 2006, respectively. Mr. Creel served as President, CEO and a Director of EPE Holdings from August 2005 through August 2007. From October 2006 to August 2007, Mr. Creel served as the CFO and an Executive Vice President of DEP GP. From October 2005 through December 2009, Mr. Creel served as a Director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, which filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in October 2009 and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc.

A. James Teague. Mr. Teague was elected an Executive Vice President of EPGP in November 1999 and additionally as EPGP's Chief Commercial Officer and a Director in July 2008. He also serves as a Director of EPE Holdings (since October 2009) and as Director, Executive Vice President and Chief Commercial Officer of DEP GP (since July 2008). Mr. Teague joined EPGP in connection with its purchase of certain midstream energy assets from affiliates of Shell in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for Mapco Inc.

Charles E. McMahen. Mr. McMahen was elected a Director of EPE Holdings in August 2005 and serves as Chairman of its ACG Committee. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a Director of Compass Bancshares, and its successor, BBVA Compass Bank, since 2001. He also served as chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

Edwin E. Smith. Mr. Smith was elected a Director of EPE Holdings in August 2005 and is a member of its ACG Committee. Mr. Smith has been a private investor since he retired from Allied Bank of Texas in 1989 after a 31-year career in banking. Mr. Smith serves as a Director of Encore Bank and previously served as a director of EPCO from 1987 until 1997.

Thurmon M. Andress. Mr. Andress was elected a Director of EPE Holdings in November 2006 and is a member of its ACG Committee. Mr. Andress serves as the Managing Director – Houston for Breitburn Energy Company L.P. and is a former member of its Board of Directors. In 1990, he founded Andress Oil & Gas Company, serving as its President and CEO until it merged with Breitburn Energy Company L.P. in 1998. In 1982, he founded Bayou Resources, Inc. a publicly traded energy company that was sold in 1987. From 2002 through December 2009, Mr. Andress served as a member of the Board of Directors of Edge Petroleum Corp. (including its Governance and Compensation Committees). In October 2009, Edge Petroleum Corp. filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc. Mr. Andress is currently a member of the National Petroleum Council (including its Board) and serves on the Board of Governors of Houston for the Independent Petroleum Association of America. In 1993, Mr. Andress was inducted into All American Wildcatter's, a 100-member organization dedicated to American oil and gas explorationists and producers.

William Ordemann. Mr. Ordemann was elected an Executive Vice President and the Chief Operating Officer of EPGP in August 2007. He was also elected an Executive Vice President of DEP GP in August 2007. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined Enterprise Products Partners in connection with its purchase of certain midstream energy assets from affiliates of Shell in 1999. Prior to joining Enterprise Products Partners, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

Bryan F. Bulawa. Mr. Bulawa was elected Senior Vice President and Treasurer of EPGP, EPE Holdings and DEP GP in October 2009, having served as Vice President and Treasurer of EPGP since July 2007. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he served as director of the firm’s U.S. Energy Corporate Finance and Distribution group.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected a Senior Vice President of EPGP in February 2005, having served as a Vice President of EPGP since August 2000. Mr. Knesek has been the Principal Accounting Officer and Controller of EPGP since August 2000, of EPE Holdings since August 2005 and of DEP GP since September 2006. He has served as Senior Vice President of EPE Holdings since August 2005 and of DEP GP since September 2006. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that the following persons should serve as a director of our general partner.

Eight of our directors are current or former employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include: for Mr. Duncan, over 55 years of ownership and management of a number of midstream businesses, including as one of the founders of Enterprise Products Partners; for Dr. Cunningham, over 45 years of refined products, chemicals and midstream businesses; for Mr. Fowler, over ten years of experience with our midstream assets, including finance, accounting (inactive certified public accountant) and investor public relations and, for over the last six years, as a member of Enterprise Products Partners’ executive management team; for Mr. Bachmann, over 28 years of experience with our midstream assets, including legal, regulatory, contract and merger and acquisitions and, for over the last ten years, as a member of Enterprise Products Partners’ executive management team; for Ms. Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO’s businesses, including ownership and management of Enterprise Products Partners’ businesses; for Mr. Andras, over 50 years of management and commercial roles in a number of midstream businesses, including over 25 years as the former CEO of EPCO until 2003 and the initial CEO of the general partner of Enterprise Products Partners from the date of Enterprise Products Partners’ IPO until early 2005; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise Products Partners, including finance and accounting (certified public accountant) and more than six years of management experience in the financial industry; and for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for the Enterprise Products Partners’ businesses.

Our three outside directors also have significant experience in our industry in a variety of capacities, as well as other qualifications, attributes and skills. These include: for Mr. McMahen, banking and finance; for Mr. Smith, banking and investments; and for Mr. Andress, oil and gas exploration and production.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, EPE Holdings, directors and executive officers of EPE Holdings, certain other officers, and any persons holding more than 10% of the Parent Company’s Units are required to report their beneficial ownership of Units and any changes in their beneficial ownership levels to the Parent Company and the SEC. Specific due dates for these reports have been established by regulation, and the Parent Company is required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2009, except that on March 3, 2009, Mr. McMahen filed a late Form 4 reporting two purchase transactions that he inadvertently failed to timely report during 2006.

Item 11. *Executive Compensation*.

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, a privately held company controlled by Dan L. Duncan. Our management, administrative and operating functions are primarily performed by employees of EPCO pursuant to the ASA. Pursuant to the ASA, we reimburse EPCO for 100% of EPCO's compensation costs related to our partnership. For additional information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Summary Compensation Table

The following table presents total compensation amounts, paid, accrued or otherwise expensed by us with respect to the years ended December 31, 2009, 2008 and 2007 for the CEO, CFO and three other most highly compensated executive officers of our general partner as of December 31, 2009. Collectively, these five individuals were our "named executive officers" for 2009.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Comp. ($) (4)	Total ($)
Dr. Ralph S. Cunningham	2009	$ 420,000	$ 318,750	$ 1,724,470	$ 499,050	$ 163,070	$ 3,125,340
(President and CEO)	2008	408,188	255,000	2,692,906	107,100	107,482	3,570,676
	2007	398,813	242,250	1,834,627	120,600	53,626	2,649,916
W. Randall Fowler	2009	262,500	450,000	1,236,159	307,838	101,931	2,358,428
(Executive Vice President and CFO)	2008	254,375	175,000	1,836,608	71,400	83,528	2,420,911
	2007	258,495	157,320	1,200,844	67,295	64,791	1,748,745
Michael A. Creel	2009	580,000	1,280,000	2,616,695	718,920	216,630	5,412,245
(President and CEO	2008	563,200	552,000	3,668,620	171,360	200,241	5,155,421
of Enterprise Products Partners)	2007	399,893	403,830	1,599,795	105,163	119,387	2,628,068
A. James Teague	2009	650,000	950,000	2,445,585	665,400	233,747	4,944,732
(Executive Vice President and	2008	558,333	500,000	3,627,701	142,800	176,651	5,005,485
Chief Commercial Officer)	2007	445,660	300,000	2,175,230	160,800	110,336	3,192,026
Richard H. Bachmann	2009	427,313	629,375	1,824,747	440,828	156,662	3,478,925
(Executive Vice President and	2008	447,125	297,500	2,724,190	99,960	165,354	3,734,129
Chief Legal Officer)	2007	378,408	229,338	1,509,286	99,214	121,149	2,337,395

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards for 2009 were paid in February 2010).

(2) Amounts represent the aggregate grant date fair value of restricted unit and profits interests awards in the Employee Partnerships granted during each year presented. For information about assumptions made in the valuation of these awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which information is incorporated by reference herein.

(3) Amounts represent the aggregate grant date fair value of unit option awards granted during each year presented. For information about assumptions made in the valuation of these awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which information is incorporated by reference herein.

(4) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.

Each of the named executive officers continues to perform services for other affiliates of EPCO. Under the ASA, the compensation costs of our named executive officers are allocated to us and our affiliates based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly.

The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses, which include Enterprise Products Partners and Duncan Energy Partners, and those of our other affiliates for each of the years presented.

Named Executive Officer	Year	Enterprise GP Holdings	EPCO and other affiliates	Total Time Allocated
Dr. Ralph S. Cunningham (CEO)	2009	75%	25%	100%
	2008	75%	25%	100%
	2007	75%	25%	100%
W. Randall Fowler (CFO)	2009	50%	50%	100%
	2008	50%	50%	100%
	2007	56%	44%	100%
Michael A. Creel	2009	80%	20%	100%
	2008	80%	20%	100%
	2007	65%	35%	100%
A. James Teague	2009	100%	--	100%
	2008	100%	--	100%
	2007	100%	--	100%
Richard H. Bachmann	2009	66%	34%	100%
	2008	70%	30%	100%
	2007	62%	38%	100%

Compensation Discussion and Analysis

With respect to our named executive officers, compensation paid or awarded by us 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. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to the compensation of our named executive officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by the Board or the ACG Committee of our general partner. Equity awards under EPCO's long-term incentive plans are approved by the ACG Committee of the respective issuer. We do not have a separate compensation committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objectives of EPCO's compensation program are to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. Our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels. With respect to the three years ended December 31, 2009, EPCO's compensation package for named executive officers did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the three years ended December 31, 2009, the elements of compensation for the named executive officers consisted of the following:

§ Annual cash base salary;

§ Discretionary annual cash bonus awards;

§ Awards under long-term incentive arrangements; and

§ Other compensation, including very limited perquisites.

In order to assist Mr. Duncan and EPCO with compensation decisions, Mr. Creel and Dr. Cunningham (both Group Vice Chairmen for EPCO) and the senior vice president of Human Resources for EPCO formulate preliminary compensation recommendations for each of the named executive officers other than our CEO. Mr. Duncan, after consulting with the senior vice president of Human Resources for EPCO, independently makes compensation decisions with respect to the named executive officers. In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain 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 executive officers. In 2009, EPCO engaged Hewitt & Associates ("Hewitt") to review executive compensation relative to our industry. Hewitt provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and external trends. Neither we, nor EPCO, which engages the consultant, are aware of the identity of the companies whose data was used from the consultant's proprietary data base for specific positions. EPCO uses the information provided in the Hewitt analysis to gauge whether compensation levels reported by the consultant are 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, for which Dan L. Duncan has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' 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 all elements of compensation and the appropriate balance of internal pay equity among executive officers. Mr. Duncan and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority, except for equity awards under EPCO's long-term incentive plans, as discussed below.

We believe the absence of specific performance-based criteria associated with our cash compensation and equity awards, and the long-term nature of our equity awards, has the effect of discouraging 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.

The discretionary cash bonus awards paid to each of our named executive officers were determined by consultation, as appropriate, among Mr. Duncan, Mr. Creel, Dr. Cunningham, Mr. Bachmann and the senior vice president of Human Resources for EPCO, subject to Mr. Duncan's final determination. These cash bonus 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, as well as the performance of other EPCO affiliates for which the named executive officers perform services. It is EPCO's general policy to pay these awards in February of the following year.

The awards granted under EPCO's long-term incentive plans to our named executive officers were determined by consultation among Mr. Duncan, Mr. Creel and the senior vice president of Human Resources for EPCO, and were approved by the ACG Committee of the respective issuer. In addition, our named executive officers are Class B limited partners in certain of the Employee Partnerships. Mr. Duncan approves the issuance of all limited partnership interests in the Employee Partnerships to our named executive officers. See "Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants" below for information regarding EPCO's long-term 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 limited perquisites allocable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2009.

In December 2009, EPCO and the partners of each of the Employee Partnerships amended the partnership agreement of each of the Employee Partnerships to provide that the expected liquidation date for such Employee Partnership will be in February 2016. The extensions of the expected liquidation dates were intended to align the interests of the employee partners of the Employee Partnerships with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships, which also hold indirectly a significant ownership interest in both us and our subsidiaries.

Also in December 2009, the Board implemented certain equity ownership guidelines for directors and executive officers of our general partner in order to further align their interests and actions with the interests of our partnership and its unitholders. See "Security Ownership of Management" within Item 12 of this annual report for additional information. Our compensation practices for our named executive officers are not expected to be impacted by this new policy.

We believe that each of the base salary, cash bonus awards, and long-term incentive awards fit the overall compensation objectives of us and of EPCO and are designed to avoid risks that are likely to conflict with the partnership's risk management policies.

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Grants of Plan-Based Awards in Fiscal Year 2009

The following table presents information concerning each grant of a plan-based award made to a named executive officer in 2009 for which we will be allocated by EPCO our pro rata share under the ASA. The restricted unit and unit option awards granted during 2009 were under EPCO's long-term incentive plans. See "Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants" within this discussion of compensation of directors and executive officers for additional information regarding the long-term incentive plans under which these awards were granted.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted unit awards: (2)						
Dr. Ralph S. Cunningham (CEO)	5/6/09	--	34,000	--	--	$ 635,460
W. Randall Fowler (CFO)	5/6/09	--	34,000	--	--	423,640
Michael A. Creel	5/6/09	--	50,600	--	--	1,008,762
A. James Teague	5/6/09	--	37,400	--	--	932,008
Richard H. Bachmann	5/6/09	--	37,400	--	--	617,455
Unit option awards: (3)						
Dr. Ralph S. Cunningham (CEO)	2/19/09	--	60,000	--	22.06	298,350
	5/6/09	--	60,000	--	24.92	200,700
W. Randall Fowler (CFO)	2/19/09	--	52,500	--	22.06	174,038
	5/6/09	--	60,000	--	24.92	133,800
Michael A. Creel	2/19/09	--	75,000	--	22.06	397,800
	5/6/09	--	90,000	--	24.92	321,120
A. James Teague	2/19/09	--	60,000	--	22.06	397,800
	5/6/09	--	60,000	--	24.92	267,600
Richard H. Bachmann	2/19/09	--	60,000	--	22.06	263,543
	5/6/09	--	60,000	--	24.92	177,285
Profits interest awards: (4)						
Dr. Ralph S. Cunningham (CEO)	12/2/09	--	--	--	--	1,089,009
W. Randall Fowler (CFO)	12/2/09	--	--	--	--	812,519
Michael A. Creel	12/2/09	--	--	--	--	1,607,933
A. James Teague	12/2/09	--	--	--	--	1,513,577
Richard H. Bachmann	12/2/09	--	--	--	--	1,207,292

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the average percentage of time each named executive officer spent on our consolidated business activities during 2009. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will equal these amounts over the vesting period.

(2) Awards granted during 2009 were made under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan").

(3) Awards granted during 2009 were made under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").

(4) Awards represent each named executive officer's share of the aggregate incremental fair value resulting from the extension of the liquidation date (a material modification of the underlying awards) of each Employee Partnership to February 2016.

The grant date fair value amounts presented in the table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our fair value assumptions made in connection with equity-based compensation.

Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants

The following information summarizes the principal types of awards granted to our named executive officers under EPCO's long-term incentive plans. These plans provide for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates.

Awards granted under the 1998 Plan may be in the form of unit options, restricted units, phantom units, unit appreciation rights ("UARs") and distribution equivalent rights ("DERs"). Awards granted under the 2008 Plan may be in the form of unit options, restricted units, phantom units, UARs and DERs. As of December 31, 2009, no phantom unit awards, UARs or associated DERs have been granted under the EPCO plans to the named executive officers. No awards with respect to the Parent Company's Units or Enterprise Products Partners common units have been granted in connection with these long-term incentive plans.

As additional long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies "profits interests" in the Employee Partnerships, which are privately held affiliates of EPCO. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without any capital contributions.

Restricted unit awards. Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. For awards granted prior to 2010, the restrictions on such awards generally lapse four years from the date of grant. Beginning in 2010, new restricted unit grants will vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted units is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by the respective issuer.

Unit option awards. Under the EPCO plans, non-qualified incentive options to purchase a fixed number of common units of Enterprise Products Partners may be granted to key employees of EPCO. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the EPCO plans have a vesting period of four years and remain exercisable for five to ten years, as applicable, from the date of grant.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on common units of Enterprise Products Partners, and expected unit price volatility of common units of Enterprise Products Partners. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of Enterprise Products Partners' historical unit price volatility and distribution yield over a period equal to the expected life of the option.

Profits interests awards. Profits interest awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which the named executive officers participate own either units of The Parent Company or Enterprise Products Partners or a combination of both.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment ("Capital Base") in the Employee Partnership and residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest.

The estimated grant date fair values of the profits interests awards were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. The profits interests awards are subject to forfeiture.

The following table presents each named executive officer's share of the total profits interest in the Employee Partnerships at December 31, 2009:

		Percentage Ownership of Class B Interests			
Named Executive Officer	**EPE Unit I**	**EPE Unit II**	**EPE Unit III**	**Enterprise Unit**	**EPCO Unit**
Dr. Ralph S. Cunningham (CEO)	--	100%	8.9%	10.3%	20.0%
W. Randall Fowler (CFO)	6.2%	--	8.9%	8.2%	20.0%
Michael A. Creel	9.3%	--	8.9%	18.5%	20.0%
A. James Teague	6.2%	--	7.4%	10.3%	20.0%
Richard H. Bachmann	9.3%	--	8.9%	10.3%	20.0%

Equity Awards Outstanding at December 31, 2009

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2009. We expect to be allocated our pro rata share of the expense associated with such awards under the ASA. As a result, the gross amounts listed in the tables do not represent the amount of expense we expect to recognize in connection with these awards.

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The following table presents information concerning each named executive officer's restricted unit and options awards outstanding at December 31, 2009. The referenced units in the table below are common units of Enterprise Products Partners.

		Option Awards				Unit Awards	
Name	Vesting Date	Number of Units Underlying Options Exercisable (#)	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#)(2)	Market Value of Units That Have Not Vested ($)(3)
Restricted unit awards:							
Dr. Ralph S. Cunningham (CEO)	Various (1)	--	--	--	--	100,600	$ 3,159,846
W. Randall Fowler (CFO)	Various (1)	--	--	--	--	91,100	2,861,451
Michael A. Creel	Various (1)	--	--	--	--	129,100	4,055,031
A. James Teague	Various (1)	--	--	--	--	104,000	3,266,640
Richard H. Bachmann	Various (1)	--	--	--	--	104,000	3,266,640
Unit option awards:							
Dr. Ralph S. Cunningham (CEO)							
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	--	60,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	60,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
W. Randall Fowler (CFO)							
August 4, 2005 option grant	8/04/09	25,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	--	45,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	52,500	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
Michael A. Creel							
August 4, 2005 option grant	8/04/09	35,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	--	60,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	90,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	75,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	90,000	24.92	12/31/14	--	--
A. James Teague							
August 4, 2005 option grant	8/04/09	35,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	--	60,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	60,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
Richard H. Bachmann							
August 4, 2005 option grant	8/04/09	35,000	--	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	--	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	--	60,000	30.96	12/31/12	--	--
May 22, 2008 option grant	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	60,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--

(1) Of the 528,800 restricted unit awards presented in the table, 60,000 vest in 2010, 123,000 vest in 2011, 152,400 vest in 2012 and 193,400 vest in 2013.

(2) Amounts represent the total number of restricted unit awards granted to each named executive officer.

(3) Amounts derived by multiplying the total number of restricted unit awards outstanding for each named executive officer by the closing price of Enterprise Products Partners' common units at December 31, 2009 of $31.41 per unit.

The following table presents information concerning each named executive officer's nonvested profits interest awards at December 31, 2009:

Name	Vesting Date (1)	Option Awards: Number of Units Underlying Options Unexercisable (#)	Option Awards: Option Exercise Price ($/Unit)	Option Awards: Option Expiration Date	Unit Awards: Number of Units That Have Not Vested (#)	Unit Awards: Market Value of Units That Have Not Vested ($)
EPE Unit I:						
W. Randall Fowler (CFO)	8/23/10	--	--	--	--	$ 1,109,396
Michael A. Creel	8/23/10	--	--	--	--	1,651,767
A. James Teague	8/23/10	--	--	--	--	1,109,396
Richard H. Bachmann	8/23/10	--	--	--	--	1,651,767
EPE Unit II:						
Dr. Ralph S. Cunningham (CEO)	12/05/11	--	--	--	--	15,717
Enterprise Unit:						
Dr. Ralph S. Cunningham (CEO)	2/20/14	--	--	--	--	654,863
W. Randall Fowler (CFO)	2/20/14	--	--	--	--	523,890
Michael A. Creel	2/20/14	--	--	--	--	1,178,753
A. James Teague	2/20/14	--	--	--	--	654,863
Richard H. Bachmann	2/20/14	--	--	--	--	654,863
EPCO Unit:						
Dr. Ralph S. Cunningham (CEO)	11/13/13	--	--	--	--	47,506
W. Randall Fowler (CFO)	11/13/13	--	--	--	--	47,506
Michael A. Creel	11/13/13	--	--	--	--	47,506
A. James Teague	11/13/13	--	--	--	--	47,506
Richard H. Bachmann	11/13/13	--	--	--	--	47,506

(1) In December 2009, the partnership agreements of each Employee Partnership were amended to provide that the expected liquidation date for each Employee Partnership be extended to February 2016. The extensions of the expected liquidation dates are intended to align the interests of the employee partners of each Employee Partnership with the long-term interests of EPCO and other unitholders by providing an incentive to such employees to devote themselves to maximizing the value of the underlying publicly traded partnerships over an extended period of time.

The profits interest awards of the remaining Employee Partnerships had no market (or assumed liquidation) value at December 31, 2009 due to a decrease in the market value of the limited partner interests owned by each Employee Partnership since formation.

Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted units (in each case, including common units of Enterprise Products Partners) to our named executive officers during the year ended December 31, 2009 for which we were historically responsible for a share of the related expense of such awards.

Name	Option Awards: Number of Units Acquired on Exercise (#)	Option Awards: Gross Value Realized on Exercise ($) (1)	Unit Awards: Number of Units Acquired on Vesting (#)	Unit Awards: Gross Value Realized on Vesting ($) (2)
W. Randall Fowler (CFO)	10,000	$ 93,200	6,000	$ 168,300
Michael A. Creel	35,000	330,400	10,000	280,500
A. James Teague	35,000	326,200	10,000	280,500
Richard H. Bachmann	35,000	330,400	10,000	280,500

(1) Amount determined by multiplying the number of units acquired on exercise of the options by the difference between the closing price of Enterprise Products Partners' common units on the date of exercise less the exercise price.
(2) Amount determined by multiplying the number of restricted unit awards that vested during 2009 by the closing price of Enterprise Products Partners' common units on the date of vesting.

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, 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 Mr. Duncan and EPCO alone (except for equity awards, as previously noted), and not by our Board.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2009.

Submitted by: Dan L. Duncan
Dr. Ralph S. Cunningham
O.S. Andras
Thurmon Andress
Michael A. Creel
Charles E. McMahen
Edwin E. Smith
A. James Teague
Randa Duncan Williams
Richard H. Bachmann
W. Randall Fowler

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 annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during 2009. As previously noted, we do not have a separate compensation committee. Mr. Duncan and EPCO alone make compensation policies (except for equity awards, as previously noted), and not our Board.

Director Compensation

Neither we nor EPE Holdings provide any additional compensation to employees of EPCO who serve as directors of our general partner. The following table presents information regarding compensation to the independent directors of our general partner, Messrs. McMahen, Smith and Andress, during the year ended December 31, 2009.

Name	Fees Earned or Paid in Cash ($)
Charles E. McMahen	$ 90,000
Edwin E. Smith	$ 75,000
Thurmon Andress	$ 75,000

For 2009, the independent directors were compensated for their services as follows: (i) each received a $75,000 cash retainer annually and (ii) if the individual served as chairman of a committee of the Board, then he received an additional $15,000 in cash annually. Effective January 1, 2010, the annual compensation arrangements for our independent directors changed to the following:

§ Each independent director will receive $75,000 in cash annually;

§ If the individual serves as chairman of a committee of the Board of Directors, then he will receive an additional $15,000 in cash annually;

§ Each independent director will receive a meeting fee of $1,500 in cash for each meeting of the Board attended. In addition, each independent director will receive a meeting fee of $1,500 in cash for each meeting of a duly appointed committee of the Board attended, provided that he is duly elected or appointed to the committee; and

§ Each independent director shall receive an annual grant of our Units having a fair market value, based on the closing price of our Units on the trading day immediately preceding the date of grant, of $40,000.

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

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 1, 2010, regarding each person known by our general partner to beneficially own more than 5% of the Parent Company's Units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Units	Dan L. Duncan	108,503,133 (1)	78.0%
	1100 Louisiana Street, 10th Floor		
	Houston, Texas 77002		

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

Security Ownership of Management

The following sets forth certain information regarding the beneficial ownership of the Parent Company's Units and the common units of Enterprise Products Partners and Duncan Energy Partners as of February 1, 2010 by (i) our named executive officers; (ii) the current directors of EPE Holdings; and (iii) the current directors and executive officers of EPE Holdings as a group. Enterprise Products Partners is a consolidated subsidiary of the Parent Company and Duncan Energy Partners is a consolidated subsidiary of Enterprise Products Partners.

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

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the securities beneficially owned by affiliates of EPCO. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of members of Mr. Duncan's family. The address of EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

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

Borrowings under the EPE Revolver, Term Loan A and Term Loan B are secured by the Parent Company's ownership of (i) 20,242,179 common units of Enterprise Products Partners, (ii) 100% of the membership interests in EPGP and (iii) 38,976,090 common units of Energy Transfer Equity. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our consolidated debt obligations.

Name of Beneficial Owner	Parent Company Units: Amount and Nature Of Beneficial Ownership	Parent Company Units: Percent of Class	Enterprise Products Partners L.P. Common Units: Amount and Nature Of Beneficial Ownership	Enterprise Products Partners L.P. Common Units: Percent of Class	Duncan Energy Partners L.P. Common Units: Amount and Nature Of Beneficial Ownership	Duncan Energy Partners L.P. Common Units: Percent of Class
Dan L. Duncan:						
Units owned by EPCO:						
Through DFI Delaware Holdings, L.P.	--	--	130,506,142	21.5%	--	--
Through Duncan Family Interests, Inc.	71,860,405	51.6%	6,775,839	1.1%	--	--
Through DFI GP Holdings L.P.	25,162,804	18.1%	3,100,000	*	--	--
Through Enterprise GP Holdings L.P.	--	--	21,167,783	3.5%	--	--
Through EPCO Holdings, Inc.	75,865	*	6,182,354	1.0%	99,453	*
Units owned by EPO	--	--	--	--	33,783,587	58.6%
Units owned by DD Securities LLC	3,745,673	2.7%	1,392,686	*	103,100	*
Units owned by Employee Partnerships (1)	7,165,315	5.1%	1,623,654	*	--	--
Units owned by family trusts (2)	243,071	*	14,624,718	2.4%	--	--
Units owned personally	250,000	*	1,470,006	*	382,500	*
Total for Dan L. Duncan	108,503,133	78.0%	186,843,182	30.8%	34,368,640	59.6%
Dr. Ralph S. Cunningham (3)	4,000	*	104,739	*	3,000	*
W. Randall Fowler (3)	3,000	*	153,674	*	2,000	*
Michael A. Creel (3)	35,000	*	248,868	*	7,500	*
A. James Teague (3)	17,000	*	295,228	*	6,000	*
Richard H. Bachmann (3)	18,969	*	233,238	*	14,172	*
Randa Duncan Williams (4)	75,000	*	1,750,000	*	11,500	*--
O.S. Andras	178,571	*	1,700,000	*	--	--
Charles E. McMahen	10,167	*	--	--	20,000	*
Edwin E. Smith	20,800	*	118,204	*	34,000	*
Thurmon Andress	9,400	*	7,400	*	--	--
All current directors and executive officers of EPE Holdings, as a group (14 individuals in total)	108,878,160	78.2%	191,659,715	31.6%	34,474,162	59.8%

** Represents a beneficial ownership of less than 1% of class*

(1) As a result of EPCO's ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the limited partner interests held by these entities.

(2) Mr. Duncan is deemed beneficial owner of the limited partner interests held by certain family trusts, the beneficiaries of which are shareholders of EPCO.

(3) These individuals are named executive officers for 2009.

(4) The Parent Company Units presented for Ms. Duncan Williams are held of record by Alkek and Williams, Ltd., an affiliate of Ms. Duncan Williams. The number of Enterprise Products Partners common units presented for Ms. Duncan Williams includes 1,312,500 common units held by family trusts for which she is the trustee but has disclaimed beneficial ownership. The number of Duncan Energy Partners' common units presented for Ms. Duncan Williams includes (i) 5,000 common units held of record by Alkek and Williams, Ltd., (ii) 4,500 common units held of record by Ms. Duncan Williams' spouse and (iii) 2,000 common units held of record jointly by Ms. Duncan Williams and her spouse.

Dan L. Duncan also owns 4,520,431 Class B units, representing 100% of such class of securities, of Enterprise Products Partners L.P.

Equity Ownership Guidelines

On December 31, 2009, the ACG Committee recommended to the Board, and effective on January 1, 2010, the Board adopted and approved, new equity ownership guidelines for our general partner's directors and executive officers in order to further align their interests and actions with the interests of our general partner, us and our unitholders. Under the new guidelines:

§ each non-management director of our general partner is required to own our Units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board paid for the most recently completed calendar year; and

§ each executive officer of our general partner is required to own our Units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year; provided, however, that the value of any units representing limited partnership interests in Enterprise Products Partners or Duncan Energy Partners (each of which we refer to as an "Affiliated MLP"), owned by an executive officer of our general partner who is also an executive officer of the general partner of such Affiliated MLP, shall be counted toward the equity ownership requirements set forth above.

Securities Authorized for Issuance Under Equity Compensation Plans

In November 2005, the Parent Company filed a registration statement covering the potential future issuance of up to 250,000 of its Units in connection with the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (the "2005 Plan"). Units issued under this plan can be in the form of unit options, restricted units, phantom units and UARs. With the exception of the 90,000 UARs issued to independent directors of EPE Holdings, no other awards have been issued under the 2005 Plan. EPE Holdings has the option of issuing Units or making cash payments when the UARs vest. The 2005 Plan is effective until the earlier of (i) all available Units under the plan have been issued to participants, (ii) early termination of the 2005 Plan by EPCO or (iii) the tenth anniversary of the 2005 Plan, which is August 2015. Compensation expense associated with these awards is recognized by EPE Holdings, and not included in our consolidated compensation expense.

The following table sets forth certain information as of December 31, 2009 regarding the 2005 Plan.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Awards	Weighted-Average Exercise Price of Outstanding Awards	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:			
2005 Plan	--	--	160,000
Equity compensation plans not approved by unitholders:			
None.	--	--	--
Total for equity compensation plans	--	--	160,000

The 160,000 Units remaining available for future issuance under the 2005 Plan assumes that EPE Holdings elects to issue Units to its independent directors when the 90,000 UARs outstanding at December 31, 2009 vest.

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

Certain Relationships and Related Transactions

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. Additional information regarding our related party transactions is set forth in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report and incorporated by reference into this Item 13.

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 ASA with EPCO 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 "Partnership Management," "Corporate Governance" and "ACG Committee" within Item 10 of this annual report, the ACG Committee is comprised of three directors: Charles E. McMahen, Thurmon Andress and Edwin E. Smith. During the year ended December 31, 2009, the ACG Committee reviewed and approved the TEPPCO Merger.

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 $100.0 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 markup or discount, for those services. The ACG Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation. For a summary of the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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.

Business Opportunity Agreements

The ASA also addresses potential conflicts that may arise among the Parent Company (including EPE Holdings), Enterprise Products Partners (including EPGP), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes the Parent Company, Enterprise Products Partners, Duncan Energy Partners and their respective general partners. With respect to potential conflicts regarding third-party business opportunities, the ASA provides, among other things, that:

- § If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, or to the Parent Company (including EPE Holdings), Enterprise Products Partners (including EPGP), or Duncan Energy Partners (including DEP GP), then the Parent Company will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  - § general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  - § incentive distribution rights ("IDRs") and limited partner interests (or securities which have characteristics similar to IDRs or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

  The Parent Company will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100.0 million, the decision to decline the acquisition will be made by the CEO of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100.0 million, the CEO of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

  In the event that the Parent Company abandons the acquisition and so notifies the EPCO Group, and EPGP and DEP GP, then Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to the Parent Company, as described above but utilizing EPGP's CEO and ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

- § If any business opportunity not covered by the preceding bullet point (i.e., not involving equity securities) is presented to the EPCO Group, or to the Parent Company (including EPE Holdings), Enterprise Products Partners (including EPGP), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100.0 million, any decision to decline the business opportunity will be made by the CEO of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100.0 million, the CEO of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, the Parent Company will have the second right to pursue such business opportunity. It will be presumed that the Parent Company will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity.

Partnership Agreement Standards for ACG Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates and us, any of our subsidiaries or any partner, any resolution or course of action by our general partner or its affiliates in respect to such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our general partner's ACG Committee ("Special Approval") or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its resolution of any conflict of interest to consider:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ 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;

§ the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and

§ such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee's Special Approval is conclusively deemed fair and reasonable to us under the partnership agreement.

The 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; and

§ 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.

Director Independence

Messrs. McMahen, Smith and Andress 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 factors considered by the Board in making its independence determinations, please refer to "Corporate Governance" and "ACG Committee" under Item 10 of this annual report.

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

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

	For Year Ended December 31,	
	2009	2008
Audit Fees (1)	$ 6.0	$ 6.0
Audit-Related Fees (2)	--	--
Tax Fees (3)	--	0.2
All Other Fees (4)	N/A	N/A

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and partnership tax planning. In 2008, PricewaterhouseCoopers International Limited was engaged to perform the majority of our tax related services.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last two years.

The ACG Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the ACG Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the ACG Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The ACG Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

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

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

(2) Financial Statement Schedules: All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits.

Exhibit Number	Exhibit*
2.1	Securities Purchase Agreement, dated May 7, 2007, by and among Enterprise GP Holdings L.P., as Buyer, and Ray C. Davis, Avatar Holdings, LLC, Avatar Investments, LP, Natural Gas Partners VI, L.P., Lon Kile, and MHT Properties, Ltd., as Selling Parties, and LE GP, LLC (incorporated by reference to Exhibit 10.1 to Form 8-K filed May 10, 2007).
2.2	Securities Purchase Agreement, dated as of May 7, 2007, by and between Enterprise GP Holdings L.P., DFI GP Holdings, L.P. and Duncan Family Interests, Inc. (incorporated by reference to Exhibit 10.4 to Form 8-K filed May 10, 2007).
3.1	First Amended and Restated Agreement of Limited Partnership of Enterprise GP Holdings L.P., dated August 29, 2005 (incorporated by reference to Exhibit 3.1 to Form 10-Q filed November 4, 2005).
3.2	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Enterprise GP Holdings L.P., dated May 7, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K filed on May 10, 2007).
3.3	Amendment to the First Amended and Restated Agreement of Limited Partnership of Enterprise GP Holdings L.P., dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed on January 3, 2008).
3.4	Amendment No. 3 to the First Amended and Restated Agreement of Limited Partnership of Enterprise GP Holdings L.P., dated November 6, 2008 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed on November 10, 2008).
3.5	Third Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated November 7, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on November 9, 2007).
3.6	First Amendment to the Third Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 3.6 to Form 10-Q filed on November 10, 2008).
3.7	Second Amendment to the Third Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated October 27, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed on October 30, 2009).
3.8	Certificate of Limited Partnership of Enterprise GP Holdings L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 to Form S-1 Registration Statement, Reg. No. 333-124320, filed July 22, 2005).
3.9	Certificate of Formation of EPE Holdings, LLC (incorporated by reference to Exhibit 3.3 to Amendment No. 2 to Form S-1 Registration Statement, Reg. No. 333-124320, filed July 22, 2005).
4.1	Form of Specimen Certificate Evidencing Units Representing Limited Partner Interests in Enterprise GP Holdings L.P. (incorporated by reference to Exhibit 4.1 to Amendment No. 3 to Form S-1 Registration Statement, Reg. No. 333-124320, filed August 11, 2005).
4.2	Unit Purchase Agreement, dated July 13, 2007, by and among Enterprise GP Holdings L.P., EPE Holdings, LLC and the Purchasers named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed on July 18, 2007).

4.3	Registration Rights Agreement, dated July 17, 2007, by and among Enterprise GP Holdings L.P. and the Purchasers named therein (incorporated by reference to Exhibit 10.2 to Form 8-K filed on July 18, 2007).
4.4	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed by Enterprise Products Partners L.P. on March 10, 2000).
4.5	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed by Enterprise Products Partners L.P. on January 28, 2003).
4.6	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed by Enterprise Products Partners L.P. on March 31, 2003).
4.7	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed by Enterprise Products Partners L.P. on August 8, 2007).
4.8	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed by Enterprise Products Partners L.P. on October 6, 2004).
4.9	First Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed by Enterprise Products Partners L.P. on October 6, 2004).
4.10	Second Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on October 6, 2004).
4.11	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed by Enterprise Products Partners L.P. on October 6, 2004).
4.12	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed by Enterprise Products Partners L.P. on October 6, 2004).
4.13	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed by Enterprise Products Partners L.P. on March 3, 2005).
4.14	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on March 3, 2005).
4.15	Seventh Supplemental Indenture, dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed by Enterprise Products Partners L.P. on November 4, 2005).
4.16	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed by Enterprise Products Partners L.P. on July 19, 2006).

4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.18	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed by Enterprise Products Partners L.P. on August 8, 2007).
4.19	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on September 5, 2007).
4.20	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on April 3, 2008).
4.21	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed by Enterprise Products Partners L.P. on April 3, 2008).
4.22	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on December 8, 2008).
4.23	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on June 10, 2009).
4.24	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on October 5, 2009).
4.25	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.26	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.27	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed by Enterprise Products Partners L.P. on January 28, 2003).
4.28	Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed by Enterprise Products Partners L.P. on March 31, 2003).
4.29	Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.30	Global Note representing $500.0 million principal amount of 4.00% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement, Reg. No. 333-123150, filed by Enterprise Products Partners L.P. on March 4, 2005).

4.31	Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed by Enterprise Products Partners L.P. on March 4, 2005).
4.32	Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed by Enterprise Products Partners L.P. on March 4, 2005).
4.33	Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed by Enterprise Products Partners L.P. on March 4, 2005).
4.34	Global Note representing $500.0 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K filed by Enterprise Products Partners L.P. on March 15, 2005).
4.35	Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed by Enterprise Products Partners L.P. on November 4, 2005).
4.36	Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed by Enterprise Products Partners L.P. on November 4, 2005).
4.37	Global Note representing $500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed by Enterprise Products Partners L.P. on November 4, 2005).
4.38	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed by Enterprise Products Partners L.P. on July 19, 2006).
4.39	Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed by Enterprise Products Partners L.P. on November 9, 2007).
4.40	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on April 3, 2008).
4.41	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed by Enterprise Products Partners L.P. on April 3, 2008).
4.42	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on December 8, 2008).
4.43	Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on June 10, 2009).
4.44	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on October 5, 2009).
4.45	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on October 5, 2009).
4.46	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.47	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.48	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).

4.49	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.50	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.51	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
4.52	Indenture, dated February 20, 2002, by and 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 Subsidiary Guarantors, and First Union National Bank, National Association, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.53	First Supplemental Indenture, dated February 20, 2002, by and 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 Subsidiary Guarantors, and First Union National Bank, National Association, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.54	Second Supplemental Indenture, dated June 27, 2002, by and 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, 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 (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.55	Third Supplemental Indenture, dated January 20, 2003, by and 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 (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).
4.56	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.57	Fourth Supplemental Indenture, dated 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. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.58	Fifth Supplemental Indenture, dated 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 (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.59	Sixth Supplemental Indenture, dated 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 (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.60	Seventh Supplemental Indenture, dated 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 (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).

4.61	Eighth Supplemental Indenture, dated October 27, 2009, 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 (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.62	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to the Form 10-K filed by Enterprise Products Partners L.P. on March 1, 2010).
4.63	Indenture, dated 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 (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.64	First Supplemental Indenture, dated 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 (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.65	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 (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).
4.66	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. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.67	Third Supplemental Indenture, dated as of October 27, 2009, 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 The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.68	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to the Form 10-K filed by Enterprise Products Partners L.P. on March 1, 2010).
10.1***	Agreement of Limited Partnership of EPE Unit L.P., dated August 23, 2005 (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 1, 2005).
10.2***	First Amendment to Agreement of Limited Partnership of EPE Unit L.P., dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.3***	Second Amendment to Agreement of Limited Partnership of EPE Unit L.P., dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed July 7, 2008).
10.4***	Third Amendment to Agreement of Limited Partnership of EPE Unit L.P., dated December 2, 2009 (incorporated by reference to Exhibit 10.1 to Form 8-K filed December 8, 2009).
10.5***	Agreement of Limited Partnership of EPE Unit II, L.P., dated December 5, 2006 (incorporated by reference to Exhibit 10.13 to Form 10-K filed by Enterprise Products Partners L.P. on February 28, 2007).
10.6***	First Amendment to Agreement of Limited Partnership of EPE Unit II, L.P., dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).

10.7***	Second Amendment to Agreement of Limited Partnership of EPE Unit II, L.P., dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K filed July 7, 2008).
10.8***	Third Amendment to Agreement of Limited Partnership of EPE Unit II, L.P., dated December 2, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K filed December 8, 2009).
10.9***	Agreement of Limited Partnership of EPE Unit III, L.P., dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to Form 8-K filed on May 10, 2007).
10.10***	First Amendment to Agreement of Limited Partnership of EPE Unit III, L.P., dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.11***	Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P., dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K filed July 7, 2008).
10.12***	Third Amendment to Agreement of Limited Partnership of EPE Unit III, L.P., dated December 2, 2009 (incorporated by reference to Exhibit 10.3 to Form 8-K filed December 8, 2009).
10.13***	Agreement of Limited Partnership of Enterprise Unit L.P., dated February 20, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2008).
10.14***	First Amendment to Agreement of Limited Partnership of Enterprise Unit L.P., dated December 2, 2009 (incorporated by reference to Exhibit 10.4 to Form 8-K filed December 8, 2009).
10.15***	Agreement of Limited Partnership of EPCO Unit L.P., dated November 13, 2008 (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise Products Partners L.P. on November 18, 2008).
10.16***	First Amendment to Agreement of Limited Partnership of EPCO Unit L.P., dated December 2, 2009 (incorporated by reference to Exhibit 10.5 to Form 8-K filed December 8, 2009).
10.17***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010).
10.18***	Form of Unit Appreciation Right Grant Award (EPE Holdings LLC Directors) under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed May 8, 2006).
10.19***	Form of Unit Appreciation Right Grant Award (Enterprise Products GP, LLC Directors) under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed May 8, 2006).
10.20***	Form of Unit Appreciation Right Grant Award (DEP Holdings, LLC Directors) under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.24 to Form 10-K filed by Duncan Energy Partners L.P. on April 2, 2007).
10.21***	Form of Option Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 26, 2010).
10.22***	Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed February 26, 2010).
10.23***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed February 26, 2010).
10.24***	Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed February 26, 2010).
10.25***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.26***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before May 7, 2008 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise Products Partners L.P. on November 8, 2007).
10.27***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued on or after May 7, 2008 but before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Enterprise Products Partners L.P. on May 12, 2008).

10.28***	Amendment to Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.29***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.30***	Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise Products Partners L.P. on November 9, 2007).
10.31***	Amendment to Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.32***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.33***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.34***	Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (amended and restated as of February 23, 2010) (incorporated by reference to Exhibit 10.7 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.35***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 4.3 to Form S-8 filed by Enterprise Products Partners L.P. on May 6, 2008).
10.36***	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.8 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.37***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.38***	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.39***	Form of Non-Employee Director Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.40***	2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.41***	Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.42***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.43***	Form of Non-Employee Director Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.44	Fifth Amended and Restated Administrative Services Agreement, dated January 30, 2009, by and among EPCO, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Operating LLC, Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, LLC, TEPPCO Midstream Companies, LLC, TCTM, L.P. and TEPPCO GP, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners on February 5, 2009).

10.45	Amended and Restated Limited Liability Company Agreement of LE GP, LLC, dated May 7, 2007 (incorporated by reference to Exhibit 10.2 to Form 8-K filed May 10, 2007).
10.46	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated February 8, 2006 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Energy Transfer Equity, L.P. on February 14, 2006).
10.47	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 1, 2006 (incorporated by reference to Exhibit 3.3.1 to Form 10-K filed by Energy Transfer Equity, L.P. on November 26, 2006).
10.48	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Equity, L.P., dated November 9, 2007 (incorporated by reference to Exhibit 3.3.2 to Form 8-K filed by Energy Transfer Equity, L.P. on November 13, 2007).
10.49	Unitholder Rights and Restrictions Agreement, dated May 7, 2007, by and among Energy Transfer Equity, L.P. and Enterprise GP Holdings, L.P., Ray C. Davis and Natural Gas Partners VI, L.P. (incorporated by reference to Exhibit 10.3 to Form 8-K filed May 10, 2007).
10.50	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Enterprise Products Partners L.P. on August 10, 2005).
10.51	Amendment No. 1 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed by Enterprise Products Partners L.P. on January 3, 2008).
10.52	Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners L.P. on April 16, 2008).
10.53	Amendment No. 3 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P,, dated November 6, 2008 (incorporated by reference to Exhibit 3.5 to Form 10-Q filed by Enterprise Products Partners L.P. on November 10, 2008).
10.54	Amendment No. 4 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated October 26, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Enterprise Products Partners L.P. on October 28, 2009).
10.55	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed by Enterprise Products Partners L.P. on November 9, 2007).
10.56	First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 3.7 to Form 10-Q filed by Enterprise Products Partners L.P. on November 10, 2008).
10.57	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed by Enterprise Products Partners L.P. on June 29, 2009).
10.58	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed by Enterprise Products Partners L.P. on June 29, 2009).
10.59	Stipulation and Agreement of Compromise, Settlement and Release, dated August 5, 2009 (incorporated by reference from Exhibit 10.3 to Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009).
10.60	Second Amended and Restated Credit Agreement, dated May 1, 2007, by and among Enterprise GP Holdings L.P., as Borrower, the Lenders Party Thereto, Citicorp North America, Inc., as Administrative Agent, Lehman Commercial Paper Inc., as Syndication Agent, Citibank, N.A., as Issuing Bank, and The Bank of Nova Scotia, SunTrust Bank and Mizuho Corporate Bank, Ltd., as Co-Documentation Agent, and Citigroup Global Markets Inc. and Lehman Brothers Inc., as Co-Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.5 to Enterprise GP Holdings' Form 8-K filed May 10, 2007).

10.61	Third Amended and Restated Credit Agreement, dated August 24, 2007, among Enterprise GP Holdings L.P., the Lenders Party Thereto, Citicorp North America, Inc., as Administrative Agent, and Citibank, N.A., as Issuing Bank. (incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2007).
10.62	First Amendment to Third Amended and Restated Credit Agreement, dated November 8, 2007, among Enterprise GP Holdings L.P., the Term Loan B Lenders Party Thereto, Citicorp North America, Inc., as Administrative Agent, and Citigroup Global Markets, Inc. and Lehman Brothers Inc. as Co-Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 14, 2007).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2009, 2008, 2007, 2006 and 2005.
21.1#	List of subsidiaries as of February 1, 2010.
23.1#	Consent of Deloitte & Touche LLP.
23.2#	Consent of Grant Thornton LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Dr. Ralph S. Cunningham for Enterprise GP Holdings L.P.'s annual report on Form 10-K for the year ended December 31, 2009.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise GP Holdings L.P.'s annual report on Form 10-K for the year ended December 31, 2009.
32.1#	Section 1350 certification of Dr. Ralph S. Cunningham for Enterprise GP Holdings L.P.'s annual report on Form 10-K for the year ended December 31, 2009.
32.2#	Section 1350 certification of W. Randall Fowler for Enterprise GP Holdings L.P.'s annual report on Form 10-K for the year ended December 31, 2009.
99.1#	Consolidated balance sheets of Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, partners' capital, and cash flows for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Duncan Energy Partners L.P., TEPPCO Partners, L.P., TE Products Pipeline Company, LLC and Energy Transfer Equity, L.P. are 1-14323, 1-33266, 1-10403, 1-13603 and 1-11727, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on March 1, 2010.

ENTERPRISE GP HOLDINGS L.P.
(A Delaware Limited Partnership)

By: EPE Holdings, LLC, as General Partner

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Senior Vice President, Controller and Principal Accounting Officer of the 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 indicated on March 1, 2010.

Signature	Title (Position with EPE Holdings, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director, President and Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director, Executive Vice President and Chief Financial Officer
/s/ Richard H. Bachmann Richard H. Bachmann	Director, Executive Vice President, Chief Legal Officer and Secretary
/s/ Randa Duncan Williams Randa Duncan Williams	Director
/s/ O.S. Andras O.S. Andras	Director
/s/ Michael A. Creel Michael A. Creel	Director
/s/ A. James Teague A. James Teague	Director
/s/ Charles E. McMahen Charles E. McMahen	Director
/s/ Edwin E. Smith Edwin E. Smith	Director
/s/ Thurmon Andress Thurmon Andress	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

ENTERPRISE GP HOLDINGS L.P.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Enterprise GP Holdings L.P. and subsidiaries (the “Company”) as of December 31, 2009 and 2008, and the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements based on our audits. We did not audit the financial statements of Energy Transfer Equity L.P., an investment of the Company, which is accounted for by the use of the equity method. The Company’s equity in Energy Transfer Equity L.P.’s net income of $77.7 million and $65.6 million (with both amounts prior to the Company’s excess cost amortization – see Note 9) for the years ended December 31, 2009 and 2008, respectively, is included in the accompanying consolidated financial statements. Energy Transfer Equity L.P.’s financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Energy Transfer Equity L.P., is based solely on the report of the other auditors.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise GP Holdings L.P. and subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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 Company's internal control over financial reporting as of December 31, 2009, 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 1, 2010 expresses an unqualified opinion on the Company's internal control over financial reporting.

The consolidated financial statements give retroactive effect to the acquisition of TEPPCO Partners, L.P. (“TEPPCO”) and Texas Eastern Products Pipeline Company, LLC (“TEPPCO GP”) by Enterprise Products Partners L.P. on October 26, 2009, which has been accounted for at historical cost as a reorganization of entities under common control as described in Notes 1 and 11 to the consolidated financial statements. Also, as discussed in Note 1 to the consolidated financial statements, the disclosures in the accompanying consolidated financial statements have been retrospectively adjusted for a change in the composition of reportable segments as a result of the acquisition of TEPPCO and TEPPCO GP by Enterprise Products Partners L.P.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

ENTERPRISE GP HOLDINGS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	December 31, 2009	December 31, 2008*
Current assets:		
Cash and cash equivalents	$ 55.3	$ 56.8
Restricted cash	63.6	203.8
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $16.8 at December 31, 2009 and $17.7 at December 31, 2008	3,099.0	1,993.5
Accounts receivable – related parties	38.4	35.2
Inventories	711.9	405.0
Derivative assets	113.8	218.5
Prepaid and other current assets	167.6	151.5
Total current assets	4,249.6	3,064.3
Property, plant and equipment, net	17,689.2	16,732.8
Investments in unconsolidated affiliates	2,416.2	2,510.7
Intangible assets, net of accumulated amortization of $795.0 at December 31, 2009 and $675.1 at December 31, 2008	1,064.8	1,182.9
Goodwill	2,018.3	2,019.6
Other assets	248.2	270.1
Total assets	$ 27,686.3	$ 25,780.4
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 410.6	$ 381.5
Accounts payable – related parties	70.8	17.6
Accrued product payables	3,393.0	1,845.6
Accrued expenses	108.5	65.7
Accrued interest	231.7	197.4
Derivative liabilities	106.1	316.2
Other current liabilities	233.2	292.2
Total current liabilities	4,553.9	3,116.2
Long-term debt (see Note 12)	12,427.9	12,714.9
Deferred tax liabilities	71.7	66.1
Other long-term liabilities	159.7	123.8
Commitments and contingencies		
Equity: (see Note 13)		
Enterprise GP Holdings L.P. partners' equity:		
Limited Partners:		
Units (139,191,640 Units outstanding at December 31, 2009 and 123,191,640 Units outstanding at December 31, 2008)	1,972.4	1,650.5
Class C Units (16,000,000 Class C Units outstanding at December 31, 2008)	--	380.7
General partner	**	**
Accumulated other comprehensive loss	(33.3)	(53.2)
Total Enterprise GP Holdings L.P. partners' equity	1,939.1	1,978.0
Noncontrolling interest	8,534.0	7,781.4
Total equity	10,473.1	9,759.4
Total liabilities and equity	$ 27,686.3	$ 25,780.4

** Amount is negligible.

See Notes to Consolidated Financial Statements.
*See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

ENTERPRISE GP HOLDINGS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For Year Ended December 31,		
	2009	**2008***	**2007***
Revenues:			
Third parties	$ 24,911.9	$ 34,454.2	$ 26,128.6
Related parties	599.0	1,015.4	585.2
Total revenues (see Note 14)	25,510.9	35,469.6	26,713.8
Costs and expenses:			
Operating costs and expenses:			
Third parties	22,547.6	32,861.9	24,938.2
Related parties	1,018.2	757.0	463.9
Total operating costs and expenses	23,565.8	33,618.9	25,402.1
General and administrative costs:			
Third parties	85.6	49.8	48.9
Related parties	97.2	95.0	83.0
Total general and administrative costs	182.8	144.8	131.9
Total costs and expenses	23,748.6	33,763.7	25,534.0
Equity in income of unconsolidated affiliates	92.3	66.2	13.6
Operating income	1,854.6	1,772.1	1,193.4
Other income (expense):			
Interest expense	(687.3)	(608.3)	(487.4)
Interest income	2.3	7.4	11.4
Other, net	(4.0)	4.9	60.4
Total other expense, net	(689.0)	(596.0)	(415.6)
Income before provision for income taxes	1,165.6	1,176.1	777.8
Provision for income taxes	(25.3)	(31.0)	(15.8)
Net income	1,140.3	1,145.1	762.0
Net income attributable to noncontrolling interest (see Note 13)	(936.2)	(981.1)	(653.0)
Net income attributable to Enterprise GP Holdings L.P.	$ 204.1	$ 164.0	$ 109.0
Net income allocated to: (see Note 13)			
Limited partners	$ 204.1	$ 164.0	$ 109.0
General partner	$ **	$ **	$ **
Earnings per unit: (see Note 17)			
Basic and diluted earnings per unit	$ 1.48	$ 1.33	$ 0.97

** Amount is negligible.

See Notes to Consolidated Financial Statements.
*See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

ENTERPRISE GP HOLDINGS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For Year Ended December 31,		
	2009	2008*	2007*
Net income	$ 1,140.3	$ 1,145.1	$ 762.0
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instrument losses during period	(179.6)	(170.2)	(46.9)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	294.2	96.3	9.5
Interest rate derivative instrument gains (losses) during period	12.5	(73.0)	(18.2)
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	26.4	5.5	(6.6)
Foreign currency derivative gains (losses)	(10.2)	9.3	1.3
Total cash flow hedges	143.3	(132.1)	(60.9)
Foreign currency translation adjustment	2.1	(2.5)	2.0
Change in funded status of pension and postretirement plans, net of tax	--	(1.3)	--
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	2.5	(9.9)	(3.8)
Total other comprehensive income (loss)	147.9	(145.8)	(62.7)
Comprehensive income	1,288.2	999.3	699.3
Comprehensive income attributable to noncontrolling interest	(1,064.2)	(866.1)	(614.3)
Comprehensive income attributable to Enterprise GP Holdings L.P.	$ 224.0	$ 133.2	$ 85.0

See Notes to Consolidated Financial Statements.
*See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

ENTERPRISE GP HOLDINGS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For Year Ended December 31,		
	2009	2008*	2007*
Operating activities:			
Net income	$ 1,140.3	$ 1,145.1	$ 762.0
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	836.8	740.1	662.8
Non-cash impairment charges	33.5	--	--
Equity in income of unconsolidated affiliates	(92.3)	(66.2)	(13.6)
Distributions received from unconsolidated affiliates	169.3	157.2	116.9
Operating lease expenses paid by EPCO	0.7	2.0	2.1
Gain from asset sales and related transactions	--	(4.0)	(67.4)
Loss on forfeiture of investment in Texas Offshore Port System	68.4	--	--
Loss on early extinguishment of debt	--	1.6	1.6
Deferred income tax expense	4.5	6.2	7.6
Changes in fair market value of derivative instruments	(0.9)	(0.9)	3.3
Effect of pension settlement recognition	(0.1)	(0.1)	0.6
Unamortized debt issuance costs	--	--	3.3
Net effect of changes in operating accounts (see Note 20)	250.1	(414.6)	457.6
Net cash flows provided by operating activities	2,410.3	1,566.4	1,936.8
Investing activities:			
Capital expenditures	(1,584.3)	(2,539.6)	(2,749.1)
Contributions in aid of construction costs	17.8	27.2	57.7
Decrease (increase) in restricted cash	140.2	(132.8)	(47.3)
Cash used for business combinations (see Note 10)	(107.3)	(553.5)	(35.9)
Acquisition of intangible assets	(1.4)	(5.8)	(14.5)
Investments in unconsolidated affiliates	(19.6)	(64.7)	(1,921.1)
Proceeds from asset sales and related transactions	3.6	22.3	169.1
Other investing activities	3.3	--	--
Cash used in investing activities	(1,547.7)	(3,246.9)	(4,541.1)
Financing activities:			
Borrowings under debt agreements	7,494.2	13,255.5	11,416.7
Repayments of debt	(7,766.7)	(10,514.9)	(8,652.0)
Debt issuance costs	(14.9)	(27.5)	(39.2)
Cash distributions paid to partners	(266.7)	(213.1)	(159.0)
Cash distributions paid to noncontrolling interest	(1,322.1)	(1,182.1)	(1,073.9)
Cash contributions from noncontrolling interest	1,014.2	446.4	372.7
Cash contributions from partners	--	--	0.1
Net cash proceeds from issuance of our Units, net	--	--	739.4
Cash distributions paid to former owners of TEPPCO interests	--	--	(29.8)
Repurchase of restricted units and options by subsidiary	--	--	(1.6)
Acquisition of treasury units by subsidiary	(2.1)	(1.9)	--
Monetization of interest rate derivative instruments (see Note 6)	0.2	(66.5)	49.1
Cash provided by (used in) financing activities	(863.9)	1,695.9	2,622.5
Effect of exchange rate changes on cash flows	(0.2)	(0.5)	0.4
Net change in cash and cash equivalents	(1.3)	15.4	18.2
Cash and cash equivalents, January 1	56.8	41.9	23.3
Cash and cash equivalents, December 31	$ 55.3	$ 56.8	$ 41.9

See Notes to Consolidated Financial Statements.
*See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

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ENTERPRISE GP HOLDINGS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 13 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss))
(Dollars in millions)

	Enterprise GP Holdings L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2006*	$ 1,418.8	$ **	$ 0.5	$ 7,549.7	$ 8,969.0
Net income	109.0	**	--	653.0	762.0
Operating lease expenses paid by EPCO	0.1	--	--	2.0	2.1
Cash distributions paid to partners	(159.0)	**	--	--	(159.0)
Cash distributions to former owners of TEPPCO GP interests	(29.8)	--	--	--	(29.8)
Net cash proceeds from issuance of Units	739.4	--	--	--	739.4
Cash distributions paid to noncontrolling interest	--	--	--	(1,073.9)	(1,073.9)
Cash contributions from noncontrolling interest	--	--	--	372.7	372.7
Repurchase of restricted units and options by subsidiary	--	--	--	(1.6)	(1.6)
Amortization of equity awards	0.6	--	--	10.4	11.0
Foreign currency translation adjustment	--	--	0.1	1.9	2.0
Cash flow hedges	--	--	(19.2)	(41.7)	(60.9)
Proportionate share of other comprehensive loss of unconsolidated affiliates	--	--	(3.8)	--	(3.8)
Other	--	--	0.1	1.0	1.1
Balance, December 31, 2007*	2,079.1	**	(22.3)	7,473.5	9,530.3
Net income	164.0	**	--	981.1	1,145.1
Operating lease expenses paid by EPCO	0.1	--	--	1.9	2.0
Cash distributions paid to partners	(213.1)	**	--	--	(213.1)
Cash distributions paid to noncontrolling interest	--	--	--	(1,182.1)	(1,182.1)
Cash contributions from noncontrolling interest	--	--	--	446.4	446.4
Acquisition of treasury units by subsidiary	--	--	--	(1.9)	(1.9)
Issuance of units by subsidiary in connection with an acquisition (see Note 10)	--	--	--	186.6	186.6
Amortization of equity awards	1.1	--	--	13.1	14.2
Acquisition of additional noncontrolling interests in affiliates	--	--	--	(22.3)	(22.3)
Change in funded status of pension and postretirement plans, net of tax	--	--	(0.1)	(1.2)	(1.3)
Foreign currency translation adjustment	--	--	(0.1)	(2.4)	(2.5)
Cash flow hedges	--	--	(20.8)	(111.3)	(132.1)
Proportionate share of other comprehensive loss of unconsolidated affiliates	--	--	(9.9)	--	(9.9)
Balance, December 31, 2008*	2,031.2	**	(53.2)	7,781.4	9,759.4
Net income	204.1	**	--	936.2	1,140.3
Operating lease expenses paid by EPCO	--	--	--	0.7	0.7
Cash distributions paid to partners	(266.7)	**	--	--	(266.7)
Cash distributions paid to noncontrolling interest	--	--	--	(1,322.1)	(1,322.1)
Cash contributions from noncontrolling interest	--	--	--	1,014.2	1,014.2
Acquisition of treasury units by subsidiary	--	--	--	(2.1)	(2.1)
Deconsolidation of Texas Offshore Port System	--	--	--	(33.4)	(33.4)
Acquisition of interest in subsidiary	--	--	--	10.3	10.3
Amortization of equity awards	3.8	--	--	20.8	24.6
Foreign currency translation adjustment	--	--	0.1	2.0	2.1
Cash flow hedges	--	--	17.3	126.0	143.3
Proportionate share of other comprehensive income of unconsolidated affiliates	--	--	2.5	--	2.5
Balance, December 31, 2009	$ 1,972.4	$ **	$ (33.3)	$ 8,534.0	$ 10,473.1

** Amount is negligible.

See Notes to Consolidated Financial Statements.
*See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

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 millions of dollars.

SIGNIFICANT RELATIONSHIPS REFERENCED IN THESE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Unless the context requires otherwise, references to “we,” “us,” “our,” “Enterprise GP Holdings” or the “Partnership” are intended to mean the business and operations of Enterprise GP Holdings L.P. and its consolidated subsidiaries.

References to the “Parent Company” mean Enterprise GP Holdings L.P., individually as the parent company, and not on a consolidated basis. References to “EPE Holdings” mean EPE Holdings, LLC, which is the general partner of the Parent Company and a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan.

References to “Enterprise Products Partners” mean Enterprise Products Partners L.P., a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD,” and its consolidated subsidiaries. Enterprise Products Partners has no business activities outside those conducted by its operating subsidiary, Enterprise Products Operating LLC (“EPO”). On October 26, 2009, Enterprise Products Partners completed the mergers of TEPPCO Partners, L.P. (“TEPPCO”) and Texas Eastern Products Pipeline Company, LLC (“TEPPCO GP”) (such related mergers referred to herein individually and together as the “TEPPCO Merger”). References to “EPGP” refer to Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. EPGP is owned by the Parent Company.

References to “Duncan Energy Partners” mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “DEP.” References to “DEP GP” mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and wholly owned by EPO.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETE.” ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETP.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). The Parent Company owns noncontrolling interests in both Energy Transfer Equity and LE GP that it accounts for using the equity method of accounting.

References to “EPCO” mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. The Parent Company, EPE Holdings, Enterprise Products Partners, EPO, EPGP, Duncan Energy Partners and DEP GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO. We do not control Energy Transfer Equity or LE GP.

References to “Employee Partnerships” mean EPE Unit L.P. (“EPE Unit I”), EPE Unit II, L.P. (“EPE Unit II”), EPE Unit III, L.P. (“EPE Unit III”), Enterprise Unit L.P. (“Enterprise Unit”) and EPCO Unit L.P. (“EPCO Unit”), collectively, all of which are privately held affiliates of EPCO.

Note 1. Partnership Organization and Basis of Presentation

Partnership Organization

The Parent Company is a publicly traded Delaware limited partnership, the limited partnership interests (the “Units”) of which are listed on the NYSE under the ticker symbol “EPE.” Our business consists of the ownership of general and limited partner interests of publicly traded partnerships engaged in the midstream energy industry and related businesses. Our goal is to increase cash distributions to unitholders. The Parent Company is owned 99.99% by its limited partners and 0.01% by its general partner, EPE Holdings.

Basis of Presentation

Our consolidated financial statements and business segments were recast in connection with the TEPPCO Merger. On October 26, 2009, the related mergers of wholly owned subsidiaries of Enterprise Products Partners with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 common units of Enterprise Products Partners for each TEPPCO unit. In total, Enterprise Products Partners issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP," have been delisted and are no longer publicly traded. On October 27, 2009, the TEPPCO and TEPPCO GP equity interests were contributed by Enterprise Products Partners to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 Class B units of Enterprise Products Partners in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as Enterprise Products Partners' common units.

Under the terms of the TEPPCO Merger agreements, the Parent Company received 1,331,681 common units of Enterprise Products Partners and an increase in the capital account of EPGP to maintain its 2% general partner interest in Enterprise Products Partners as consideration for 100% of the membership interests of TEPPCO GP.

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of EPCO and its affiliates, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are reflected as "Former owners of TEPPCO," a component of noncontrolling interest.

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

We revised our business segments and related disclosures to reflect the TEPPCO Merger. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services and (vi) Other Investments.

General Purpose Consolidated and Parent Company-Only Information. In accordance with rules and regulations of the U.S Securities and Exchange Commission ("SEC") and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of the financial information of businesses that we control through the ownership of general partner interests (e.g., Enterprise Products Partners). Our general purpose consolidated financial statements present those investments in which we do not have a controlling interest as unconsolidated affiliates (e.g., Energy Transfer Equity and LE GP). As presented in our consolidated financial statements, noncontrolling interest reflects third-party and related party ownership of our consolidated subsidiaries, which include the third-party and related party unitholders of Enterprise Products Partners and Duncan Energy Partners other than the Parent Company.

In order for the unitholders of Enterprise GP Holdings L.P. and others to more fully understand the Parent Company's business and financial statements on a standalone basis, Note 22 includes information devoted exclusively to the Parent Company apart from that of our consolidated Partnership. A key difference between the non-consolidated Parent Company financial information and those of our consolidated Partnership is that the Parent Company views each of its investments (e.g., in Enterprise Products Partners and Energy Transfer Equity) as unconsolidated affiliates and records its share of the net income of each as equity income in the Parent Company income information. In accordance with GAAP, we eliminate the equity income related to Enterprise Products Partners in the preparation of our consolidated financial statements.

Presentation of Investments. The Parent Company owns common units of Enterprise Products Partners and 100% of the membership interests of EPGP, which is entitled to 2% of the cash distributions paid by Enterprise Products Partners as well as the associated incentive distribution rights ("IDRs") of Enterprise Products Partners. At December 31, 2009 and 2008, the Parent Company owned 21,167,783 and 13,670,925 common units, respectively, of Enterprise Products Partners.

The Parent Company owns 38,976,090 common units of Energy Transfer Equity. In addition, at December 31, 2009 and 2008, the Parent Company owned approximately 40.6% and 34.9%, respectively, of the membership interests of LE GP. Energy Transfer Equity owns limited partner interests and the general partner interest of ETP. We account for our investments in Energy Transfer Equity and LE GP using the equity method of accounting. See Note 9 for additional information regarding these unconsolidated affiliates.

In May 2007, private company affiliates of EPCO contributed equity interests in TEPPCO and TEPPCO GP to the Parent Company. As a result of such contributions, the Parent Company owned 4,400,000 units of TEPPCO and all of the membership interests of TEPPCO GP, which was entitled to 2% of the cash distributions of TEPPCO as well as the IDRs of TEPPCO. On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners. As a result, the Parent Company's ownership interests in the TEPPCO units were converted to 5,456,000 common units of Enterprise Products Partners. In addition, the Parent Company's membership interests in TEPPCO GP were exchanged for (i) 1,331,681 common units of Enterprise Products Partners and (ii) EPGP (on behalf of the Parent Company as a wholly owned subsidiary of the Parent Company) was credited in its Enterprise Products Partners' capital account an amount to maintain its 2% general partner interest in Enterprise Products Partners.

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Balance at beginning of period	$ 17.7	$ 21.8	$ 23.5
Charges to expense	0.1	3.5	2.6
Payments	(1.0)	(7.6)	(4.3)
Balance at end of period	$ 16.8	$ 17.7	$ 21.8

See “Credit Risk Due to Industry Concentrations” in Note 19 for additional information.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Third-party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 13 for information regarding noncontrolling interest.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the entity’s operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the entity’s operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

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

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

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 5% of total current assets and liabilities, respectively.

Deferred Revenues

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2009 and 2008, deferred revenues totaled $106.8 million and $118.5 million, respectively, and were recorded as a component of other current and long-term liabilities, as appropriate, on our Consolidated Balance Sheets. See Note 4 for information regarding our revenue recognition policies.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates, foreign currency and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis. We also apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market value for these items on the balance sheet or income statement. Revenues and costs for these transactions are recognized when volumes are physically delivered or received. See Note 6 for additional information regarding our derivative instruments and related hedging activities.

Earnings Per Unit

Earnings per unit (“EPU”) is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 17 for additional information regarding our earnings per unit.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management’s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Balance at beginning of period	$ 22.3	$ 30.5	$ 26.0
Charges to expense	1.9	3.1	4.2
Acquisition-related additions and other	--	2.9	6.7
Payments	(5.1)	(8.3)	(6.1)
Adjustments	(2.4)	(5.9)	(0.3)
Balance at end of period	$ 16.7	$ 22.3	$ 30.5

At December 31, 2009 and 2008, $6.4 million and $5.3 million, respectively, of our environmental reserves were classified as current liabilities.

Equity Awards

See Note 5 for information regarding our accounting for equity awards.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Exchange Contracts

Exchanges are contractual agreements for the movements of natural gas liquids (“NGLs”) and certain petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued at market-based prices and included in accounts receivable. Net exchange volumes loaned to us under such agreements are valued at market-based prices and accrued as a liability in accrued product payables.

Receivables and payables arising from exchange transactions are settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs, such items are recognized in our consolidated financial statements on a net basis.

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses, and other current liabilities are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed-rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 6 for fair value information associated with our derivative instruments.

The following table presents the estimated fair values of our financial instruments at the dates indicated:

Financial Instruments	December 31, 2009 Carrying Value	December 31, 2009 Fair Value	December 31, 2008 Carrying Value	December 31, 2008 Fair Value
Financial assets:				
Cash and cash equivalents and restricted cash	$ 118.9	$ 118.9	$ 260.6	$ 260.6
Accounts receivable	3,137.4	3,137.4	2,028.7	2,028.7
Financial liabilities:				
Accounts payable and accrued expenses	4,214.6	4,214.6	2,507.8	2,507.8
Other current liabilities	233.2	233.2	292.2	292.2
Fixed-rate debt (principal amount)	10,586.7	11,056.2	9,704.3	8,192.2
Variable-rate debt	1,791.8	1,791.8	2,935.5	2,935.5

Foreign Currency Translation

We own an NGL marketing business located in Canada. The financial statements of this foreign subsidiary are translated into U.S. dollars from the Canadian dollar, which is the subsidiary's functional currency, using the current rate method. Its assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, while revenue and expense items are translated at average rates of exchange during the reporting period. Exchange gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive loss ("AOCI") in the accompanying Consolidated Balance Sheets. Our net cash flows from this Canadian subsidiary may be adversely affected by changes in foreign currency exchange rates. See Note 6 for information regarding our foreign currency derivative instruments.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. See Note 6 for information regarding impairment charges related to goodwill during 2009.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 6 for information regarding impairment charges related to long-lived assets during 2009.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. See Note 9 for information regarding impairment charges related to our unconsolidated affiliates during 2007.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax and certain federal and state tax obligations of Seminole Pipeline Company ("Seminole") and Dixie Pipeline Company ("Dixie"), both of which are consolidated subsidiaries of ours. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Since we do not have access to information regarding each partner's tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

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 settlement. See Note 16 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are valued at the lower of average cost or market ("LCM"). We capitalize, as a cost of inventory, shipping and handling charges associated with such purchase volumes, terminal storage fees, vessel inspection costs, demurrage charges and other related costs. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 7 for additional information regarding our inventories.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled: (i) on a monthly basis, (ii) at the end of the agreement or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to or received from a customer. Such in-kind deliveries are ongoing and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

The following table presents our natural gas imbalance receivables/payables at the dates indicated:

	December 31,	
	2009	**2008**
Natural gas imbalance receivables (1)	$ 24.1	$ 63.4
Natural gas imbalance payables (2)	19.0	50.8

(1) Reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheets.
(2) Reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period.

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. Under our depreciation policy for midstream energy assets, the remaining economic lives of such assets are limited to the estimated life of the natural resource basins (based on proved reserves at the time of the analysis) from which such assets derive their throughput or processing volumes. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of the remaining lease term or the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would change our depreciation amounts prospectively. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values; or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any. See Note 8 for additional information regarding our property, plant and equipment.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities; however, the cost of annual planned major maintenance projects are deferred and recognized ratably over the remaining portion of the calendar year in which such projects occur.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At December 31, 2009 and 2008, our restricted cash amounts were $63.6 million and $203.8 million, respectively. See Note 6 for information regarding derivative instruments and hedging activities.

Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectability is reasonably assured. See Note 4 for additional information regarding our revenue recognition policies.

Note 3. Recent Accounting Developments

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

Fair Value Measurements. In January 2010, the Financial Accounting Standards Board ("FASB") issued new guidance to improve disclosures about fair value measurements. This new guidance requires the following:

§ Effective with the first quarter of 2010, additional disclosures will be required regarding the reporting of transfers of fair value information between the three levels of the fair value hierarchy (i.e., Levels 1, 2 and 3).

§ Effective with the first quarter of 2011, companies will need to present purchases, sales, issuances and settlements whose fair values are based on unobservable inputs on a gross basis.

Other than requiring enhanced fair value disclosures, we do not expect our adoption of this guidance will have a material impact on our consolidated financial statements.

Consolidation of Variable Interest Entities. In June 2009, the FASB amended its consolidation guidance regarding variable interest entities. In general, this new guidance places more emphasis on a qualitative analysis, rather than a purely quantitative approach, in determining which company should consolidate a variable interest entity. Our adoption of this guidance on January 1, 2010 did not have any impact on our consolidated financial statements.

Note 4. Revenue Recognition

The following information provides a general description of our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

Our NGL Pipelines & Services include our (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines aggregating approximately 16,300 miles; (iii) NGL and related product storage and terminal facilities and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

In our natural gas processing business, we enter into percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid-contracts (i.e. a combination of percent-of-liquids and fee-based contract terms), keepwhole contracts and margin-band contracts. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and spot and contract purchases from third parties. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts and tariffs, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts and tariffs is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the Federal Energy Regulatory Commission ("FERC").

We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. Excess storage fees are collected when customers exceed their reservation amounts and are recognized in the period of occurrence. In addition, we charge other customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

We enter into fee-based arrangements and percent-of-liquids contracts for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (usually stated in cents per gallon) that is contractually subject to adjustment for changes in certain fractionation expenses (e.g. natural gas fuel costs). Certain of our NGL fractionation facilities generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGL products as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Revenues from product terminaling activities are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to our export terminal operations, revenues may also include demand payments charged to customers who reserve the use of our export facilities and later fail to use them. Demand fee revenues are recognized when the customer fails to utilize the specified export facility as required by contract.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services include approximately 19,200 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Our onshore natural gas pipelines typically generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically per million British thermal units, or “MMBtu”) multiplied by the volume gathered or delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity reserved in our pipelines whether or not the shipper actually utilizes such capacity. Revenues under firm capacity reservation agreements are recognized in the period the services are provided.

Revenues from natural gas storage contracts typically have two components: (i) monthly demand payments, which are associated with a customer’s storage capacity reservations, and (ii) storage fees per unit of volume stored at our facilities. Revenues from demand payments are recognized during the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Our natural gas marketing activities generate revenues from the sale and delivery of natural gas purchased from third parties on the open market. Revenues from these sales contracts are recognized when the natural gas is delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services include approximately 4,400 miles of onshore crude oil pipelines and 10.5 million barrels (“MMBbls”) of above-ground storage tank capacity. This segment includes our crude oil marketing activities.

Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenues associated with these arrangements are recognized when volumes have been delivered.

Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized ratably over the specified reservation period. In addition, we charge our customers throughput (or “pumpover”) fees based on volumes withdrawn from our terminals. Crude oil storage revenues are recognized ratably over the length of the storage period. Revenues are also generated from fee-based trade documentation services and are recognized as services are completed.

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers or on the open market. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

Our Offshore Pipelines & Services include our (i) offshore natural gas pipelines, (ii) offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms which serve production areas including some of the most active drilling and development regions in the Gulf of Mexico.

Revenues from our offshore pipelines are derived from fee-based agreements whereby the customer is charged a fee per unit of volume gathered or transported (typically per MMBtu of natural gas or per barrel of crude oil) multiplied by the volume delivered. Revenues associated with these fee-based contracts and tariffs are recognized when volumes have been delivered.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Revenues from platform services are recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer actually delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per million cubic feet of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub offshore platform earns a significant amount of demand revenues. The Independence Hub platform will earn $54.6 million of demand fees annually through March 2012.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services consist of (i) propylene fractionation plants and related activities, (ii) butane isomerization facilities, (iii) an octane enhancement facility, (iv) refined products pipelines, including our Products Pipeline System, and related activities and (v) marine transportation assets and other services.

Our propylene fractionation and butane isomerization facilities generate revenues through fee-based arrangements, which typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and butane isomerization. Revenues resulting from such agreements are recognized in the period the services are provided.

Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our propylene fractionation activities and purchases of petrochemical products from third parties on the open market. Revenues from these sales contracts are recognized when such products are delivered to customers. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for such factors as delivery location.

Our refined products pipelines, including our Products Pipeline System, generate revenues through fee-based contracts or tariffs as customers are billed a fixed fee per barrel of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenues associated with these fee-based contracts and tariffs are recognized when volumes have been delivered. Revenues from our refined products storage facilities are based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. Under these contracts, revenue is recognized ratably over the length of the storage period. Revenues from product terminaling activities are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded.

Revenue is also generated from the provision of 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. Under our marine services transportation contracts, revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which is generally less than ten days in duration. Revenue from these contracts is typically based on set day rates or a set fee per cargo movement. Most of the marine services transportation contracts include escalation provisions to recover 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.

The results of operations from the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels are dependent on the sales price or transportation fees that we charge our customers. Revenue is recognized for sales transactions and transportation arrangements when the product is delivered.

Note 5. Equity-based Awards

The following table summarizes the expense we recognized in connection with equity-based awards for the periods presented:

	For Year Ended December 31,		
	2009	2008	2007
Restricted unit awards (1)	$ 13.6	$ 11.3	$ 8.9
Unit option awards (1)	2.0	0.7	4.5
Unit appreciation rights (2)	--	--	0.2
Phantom units (2)	0.2	(0.5)	2.3
Profits interests awards (1)	9.2	6.6	4.4
Total compensation expense	$ 25.0	$ 18.1	$ 20.3

(1) Accounted for as equity-classified awards.
(2) Accounted for as liability-classified awards.

The fair value of an equity-classified award (e.g., a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., unit appreciation rights ("UARs")) 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-classified awards are settled in cash upon vesting.

At December 31, 2009, our active long-term incentive plans are the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"), the TEPPCO 1999 Phantom Unit Retention Plan ("1999 Plan"), the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan"). Two plans were dissolved during 2009: TEPPCO 2000 Long-Term Incentive Plan ("2000 Plan") and TEPPCO 2005 Phantom Unit Plan ("2005 Plan").

The 1998 Plan provides for awards of Enterprise Products Partners' common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and distribution equivalent rights ("DERs"). Up to 7,000,000 of Enterprise Products Partners' common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 652,543 additional common units could be issued.

The 1999 Plan provided key employees of EPCO who work on our behalf with phantom unit awards. This plan terminated in January 2010.

The 2006 Plan currently provides for awards of Enterprise Products Partners' common units (formerly of TEPPCO 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 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Effective upon the consummation of the TEPPCO Merger (see Note 1), Enterprise Products Partners assumed the vested and unvested options, restricted units and UAR awards outstanding on October 26, 2009 under the 2006 Plan and converted them into Enterprise Products Partners' options, restricted units and UAR awards based on the TEPPCO Merger exchange ratio. The vesting terms of each award and other provisions of the plan remain unchanged.

The 2008 Plan provides for awards of Enterprise Products Partners' common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Up to 10,000,000 of Enterprise Products Partners' common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 7,865,000 additional common units could be issued.

An allocated portion of the fair value of these long-term incentive plan equity-based awards is charged to us under the administrative services agreement ("ASA"). See Note 15 for a general description of the ASA with EPCO. With the exception of certain amounts recorded in connection with EPCO Unit, as defined later in this note, we are not responsible for reimbursing EPCO for any expenses associated with such awards. We recognize an expense for our allocated share of the grant date fair value of such awards, with an offsetting amount recorded in equity. Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit. Our reimbursements to EPCO during 2009 in connection with EPCO Unit were $0.7 million.

On December 10, 2009, the board of directors of DEP GP unanimously approved a resolution adopting both the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan") and the DEP Unit Purchase Plan ("DEP EUPP"). The 2010 Plan provides for awards of options to purchase Duncan Energy Partners' common units, restricted common units, UARs, phantom units and DERs to employees, directors or consultants providing services to Duncan Energy Partners. The DEP EUPP provides eligible employees the opportunity to purchase common units at a discount through withholdings from eligible compensation. On December 30, 2009, the action taken by the board of directors of DEP GP regarding the plans was approved by written consent of EPO, which held approximately 58.6% of Duncan Energy Partners' outstanding common units as of that date. Because EPO held a majority of Duncan Energy Partners' common units as of December 30, 2009, no other votes were necessary to adopt the plans. In February 2010, Duncan Energy Partners filed a registration statement with the SEC authorizing the issuance of up to 500,000 common units in connection with the 2010 Plan and 500,000 common units in connection with the DEP EUPP. The plans became effective on February 11, 2010.

Restricted Unit Awards

Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. The restrictions on such awards generally lapse four years from the date of grant. The fair value of restricted units is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. As used in the context of our long-term incentive plans, the term "restricted unit" represents a time-vested unit. Such awards are non-vested until the required service period expires.

The following table summarizes information regarding our restricted unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2006	1,105,237	$ 24.79
Granted (2)	738,040	$ 30.64
Vested	(4,884)	$ 25.28
Settled or forfeited (3)	(149,853)	$ 23.31
Restricted units at December 31, 2007	1,688,540	$ 27.23
Granted (4)	766,200	$ 30.73
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	$ 29.09
Granted (5)	1,025,650	$ 24.89
Vested	(281,500)	$ 26.70
Forfeited	(411,884)	$ 28.37
Awards assumed in connection with TEPPCO Merger	308,016	$ 27.64
Restricted units at December 31, 2009	2,720,882	$ 27.70

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued. With respect to restricted unit awards assumed in connection with the TEPPCO Merger, the weighted-average grant date fair value per unit was determined by dividing the aggregate grant date fair value of the assumed awards before an allowance for forfeitures by the number of awards assumed.
(2) Aggregate grant date fair value of restricted unit awards issued during 2007 was $22.6 million based on grant date market prices of Enterprise Products Partners' common units ranging from $28.00 to $31.83 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) Reflects the settlement of 113,053 restricted units in connection with the resignation of EPGP's former chief executive officer.
(4) Aggregate grant date fair value of restricted unit awards issued during 2008 was $23.5 million based on grant date market prices of Enterprise Products Partners' common units ranging from $25.00 to $32.31 per unit. An estimated forfeiture rate of 17% was applied to these awards.
(5) Aggregate grant date fair value of restricted unit awards issued during 2009 was $25.5 million based on grant date market prices of Enterprise Products Partners' common units ranging from $20.08 to $28.73 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.

Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by the respective issuer. Since restricted units are issued securities of Enterprise Products Partners, such distributions are reflected as a component of cash distributions to noncontrolling interest as shown on our Statements of Consolidated Cash Flows. The following table presents cash distributions with respect to Enterprise Products Partners' restricted units and supplemental information regarding its restricted units for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Cash distributions paid to restricted unit holders	$ 5.2	$ 3.9	$ 2.6
Total fair value of restricted unit awards vesting during period	$ 7.5	$ 6.6	$ 0.1

On a gross basis, the total unrecognized compensation cost of such awards was $37.9 million at December 31, 2009, of which our share is currently estimated to be $37.3 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

Unit Option Awards

Certain of our long-term incentive plans provide for the issuance of non-qualified incentive options to purchase a fixed number of Enterprise Products Partners' common units. When issued, the exercise price of each option grant may be no less than the market price of the underlying security on the date of grant. In general, options granted under the EPCO plans have a vesting period of four years and remain exercisable for five to ten years, as applicable, from the date of grant.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on Enterprise Products Partners' common units, and expected unit price volatility of Enterprise Products Partners' common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of Enterprise Products Partners' historical unit price volatility and distribution yield over a period equal to the expected life of the option.

During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, Enterprise Products Partners amended the terms of certain of its outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from Enterprise Products Partners. When employees exercise unit options, Enterprise Products Partners reimburses EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents unit option activity under the EPCO plans for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2006	2,416,000	$ 23.32		
Granted (2)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (3)	(740,000)	24.62		
Outstanding at December 31, 2007	2,315,000	26.18		
Granted (4)	795,000	30.93		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008	2,963,500	27.56		
Granted (5)	1,460,000	23.46		
Exercised	(261,000)	19.61		
Forfeited	(930,540)	26.69		
Awards assumed in connection with TEPPCO Merger	593,960	26.12		
Outstanding at December 31, 2009 (6)	3,825,920	26.52	4.6	$ 2.8
Options exercisable at:				
December 31, 2007	335,000	$ 22.06	4.0	$ 3,.3
December 31, 2008	548,500	$ 21.47	4.1	$ --
December 31, 2009 (6)	447,500	$ 25.09	4.8	$ 2.8

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options issued during 2007 was $2.4 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $30.63 per unit; (ii) expected life of options of 7.0 years; (iii) weighted-average risk-free interest rate of 4.8%; (iv) weighted-average expected distribution yield on Enterprise Products Partners' common units of 8.4% and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 23.2%.
(3) Includes the settlement of 710,000 options in connection with the resignation of EPGP's former chief executive officer.
(4) Aggregate grant date fair value of these unit options issued during 2008 was $1.9 million based on the following assumptions: (i) a grant date market price of Enterprise Products Partners' common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) risk-free interest rate of 3.3%; (iv) expected distribution yield on Enterprise Products Partners' common units of 7.0% and (v) expected unit price volatility on Enterprise Products Partners' common units of 19.8%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2008.
(5) Aggregate grant date fair value of these unit options issued during 2009 was $8.1 million based on the following assumptions: (i) a weighted-average grant date market price of Enterprise Products Partners' common units of $23.46 per unit; (ii) weighted-average expected life of options of 4.8 years; (iii) weighted-average risk-free interest rate of 2.1%; (iv) weighted-average expected distribution yield on Enterprise Products Partners' common units of 9.4% and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 57.4%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2009.
(6) Enterprise Products Partners was committed to issue 3,825,920 and 2,963,500 of its common units at December 31, 2009 and 2008, respectively, if all outstanding options awarded (as of these dates) were exercised. Of the option awards outstanding at December 31, 2009, an additional 410,000, 712,280, 736,000 and 1,520,140 are exercisable in 2010, 2012, 2013 and 2014, respectively.

The following table presents supplemental information regarding our unit options:

	For Year Ended December 31, 2009	2008	2007
Total intrinsic value of option awards exercised during period	$ 2.4	$ 0.6	$ 3.0
Cash received from EPCO in connection with the exercise of unit option awards	1.7	0.7	7.5
Option-related reimbursements to EPCO	2.4	0.6	3.0

On a gross basis, the total unrecognized compensation cost of such awards was $7.3 million at December 31, 2009 of which our share is currently estimated to be $7.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.9 years.

Profits Interests Awards

As long-term incentive arrangements, EPCO has granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in several limited partnerships (the "Employee Partnerships"), all of which are private company affiliates of EPCO. At December 31, 2009, the Employee Partnerships are EPE Unit I, EPE Unit II, EPE Unit III, Enterprise Unit and EPCO Unit. TEPPCO Unit L.P. and TEPPCO Unit II L.P. were dissolved during 2009.

Profits interests awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which our named executive officers participate own either units of the Parent Company or Enterprise Products Partners or a combination of both. The profits interests awards are subject to customary forfeiture provisions.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment (or "Capital Base") in the Employee Partnership and residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest and are a factor of the appreciation in value of the partnership's assets since its formation date.

The grant date fair value of each Employee Partnership is based on (i) the estimated value of the remaining assets, as determined using a Black-Scholes option pricing model, that would be distributed to the Class B limited partners upon dissolution of the Employee Partnership and (ii) the value, based on a discounted cash flow analysis using appropriate discount rates, of the residual quarterly cash amounts that the Class B limited partners are expected to receive over the life of the Employee Partnership.

The following table summarizes key elements of each Employee Partnership as of December 31, 2009. As used in the table in reference to the description of assets, "EPE" means Enterprise GP Holdings L.P. and "EPD" means Enterprise Products Partners L.P.

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Liquidation Date (1)	Grant Date Fair Value of Awards	Unrecognized Compensation Cost
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725%	February 2016	$21.5 million	$12.1 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725%	February 2016	$0.4 million	$0.3 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	February 2016	$42.8 million	$30.8 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2016	$6.5 million	$5.3 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	February 2016	$8.1 million	$6.5 million

(1) The liquidation date may be accelerated for change of control and other events as described in the underlying partnership agreements.

The total unrecognized compensation cost of the profits interests awards was $55.0 million at December 31, 2009 of which our share is currently estimated to be $47.6 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 6.1 years.

In December 2009, the expected liquidation date for each Employee Partnership was extended to February 2016. This modification follows a similar set of modifications made in July 2008 for EPE Unit I, EPE Unit II and EPE Unit III that extended liquidation dates as well as reduced the Class A limited partner's preferred return rates. These modifications are intended to align the interests of the employee partners of the Employee Partnerships with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships, which also hold indirectly a significant ownership interest in both us and our subsidiaries.

The following table presents the impact of modifications (e.g., extension of liquidation dates) and other changes on the aggregate grant date fair value (on an unallocated basis) of the Employee Partnerships for the periods presented.

	For Year Ended December 31,		
	2009	2008	2007
Aggregate grant date fair values at beginning of period	$ 64.6	$ 35.4	$ 12.8
New Employee Partnership grants (1,2)	--	14.6	23.0
Award modifications	19.5	15.0	--
Other adjustments, primarily forfeiture and regrant activity (2)	(4.8)	(0.4)	(0.4)
Aggregate grant date fair value at end of period	$ 79.3	$ 64.6	$ 35.4

(1) EPE Unit III was formed in 2007 and EPCO Unit and Enterprise Unit were formed in 2008.
(2) TEPPCO Unit and TEPPCO Unit II were formed during 2008 and dissolved during 2009.

The following table summarizes the assumptions we used in deriving that portion of the estimated grant date fair value for each Employee Partnership using a Black-Scholes option pricing model:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
EPE Unit I	3 to 6 years	1.2% to 5.0%	3.0% to 6.7%	16.6% to 35.0%
EPE Unit II	4 to 6 years	1.6% to 4.4%	3.8% to 6.4%	18.7% to 31.7%
EPE Unit III	4 to 6 years	1.4% to 4.9%	4.0% to 6.4%	16.6% to 32.2%
Enterprise Unit	4 to 6 years	1.4% to 3.9%	4.5% to 8.4%	15.3% to 31.7%
EPCO Unit	4 to 6 years	1.6% to 2.4%	8.1% to 11.1%	27.0% to 50.0%

Phantom Units

Certain of our long-term incentive plans provide for the issuance of phantom unit awards. These awards are automatically redeemed for cash based on the fair value of the vested portion of phantom units at redemption dates in each award. The fair value of each phantom unit award is equal to the closing market price of the underlying security on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is three to four years from the date the award is granted. Our phantom units are accounted for as liability awards.

Certain of our long-term incentive plans also provide for the award of DERs in tandem with phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of awards outstanding for the participant and the cash distribution rate per unit paid by the issuer to its unitholders. Such amounts are expensed when paid.

The following table presents additional information regarding our phantom unit awards for the periods indicated:

	Phantom Unit Awards Issued by		
	TEPPCO	Enterprise Products Partners	Total
Phantom units at December 31, 2006	154,479	--	154,479
Granted	259	--	259
Vested	(13,533)	--	(13,533)
Settled or forfeited	(13,800)	--	(13,800)
Phantom units at December 31, 2007	127,405	--	127,405
Granted	1,698	4,400	6,098
Vested	(58,168)	--	(58,168)
Settled or forfeited	(1,600)	--	(1,600)
Phantom units at December 31, 2008	69,335	4,400	73,735
Granted	124	6,200	6,324
Vested	(61,519)	--	(61,519)
Settled or forfeited	(4,447)	--	(4,447)
Awards assumed in connection with TEPPCO Merger	(3,493)	4,327	834
Phantom units at December 31, 2009	--	14,927	14,927

	For Year Ended December 31,		
	2009	2008	2007
Accrued liability for phantom unit awards, at end of period	$ 0.2	$ 1.2	$ 4.5
Liabilities paid for phantom unit awards	1.2	2.5	0.6

At December 31, 2009, only the 2008 Plan and the 1999 Plan had significant phantom units outstanding. These awards will settle as follows: 4,327 in 2010, 4,400 in 2011 and 6,200 in 2012. The 2000 Plan and 2005 Plan also issued phantom units, all of which had vested and settled prior to December 31, 2009. The 3,472 phantom units outstanding under the 1999 Plan were settled in January 2010 and the plan terminated.

Unit Appreciation Rights

UARs entitle a participant to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of the underlying security (determined as of a future vesting date) over the grant date fair value of the award. UARs are accounted for as liability awards. The following table presents additional information regarding our UARs for the periods indicated:

	UARs Issued by			
	TEPPCO	Enterprise Products Partners	EPE	Total
UARs at December 31, 2006	--	--	90,000	90,000
Granted	404,704	--	90,000	494,704
Settled or forfeited	(2,756)	--	--	(2,756)
UARs at December 31, 2007	401,948	--	180,000	581,948
Granted	29,429	--	--	29,429
UARs at December 31, 2008	431,377	--	180,000	611,377
Settled or forfeited	(166,217)	(186,614)	(90,000)	(442,831)
Awards assumed in connection with the TEPPCO Merger	(265,160)	328,810	--	63,650
UARs at December 31, 2009	--	142,196	90,000	232,196

	At December 31,		
	2009	2008	2007
Accrued liability for UARs	$ 0.3	$ 0.2	$ 0.2

At December 31, 2009, 142,196 UARs had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf. These awards are subject to five year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on Enterprise Products Partners' unit price of $37.00. If the employee resigns prior to vesting, these UAR awards are forfeited.

Prior to the TEPPCO Merger, 95,654 UARs had been granted to the non-employee former directors of TEPPCO under the 2006 Plan. The awards were settled in October 2009 and $0.1 million in cash was paid to the former directors.

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, the Parent Company, Duncan Energy Partners or Enterprise Products Partners. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. At December 31, 2009, we had a total of 90,000 outstanding UARs granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on the Parent Company's unit price of $36.68.

UARs formerly issued to non-employee directors of EPGP in the form of letter grants were terminated during the second quarter of 2009.

Note 6. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced sale. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways depending on the nature and effectiveness of the hedging activities to which they are related. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income or loss ("OCI") and is reclassified into earnings when the forecasted transaction affects earnings.

§ Foreign currency exposure - A foreign currency hedge can be treated as either a fair value hedge or a cash flow hedge depending on the risk being hedged.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of changes in the fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not occurring is immediately recognized in earnings.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at December 31, 2009, all of which were designated as hedging instruments under the FASB's derivative and hedging guidance:

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Parent Company:					
Variable-interest rate borrowings	2 floating-to-fixed swaps	$ 250.0	9/07 to 8/11	0.3% to 4.8%	Cash flow hedge
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	$ 100.0	1/04 to 2/13	6.4% to 2.8%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$ 300.0	10/04 to 10/14	5.6% to 1.5%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$ 400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Duncan Energy Partners:					
Variable-interest rate borrowings	3 floating-to-fixed swaps	$ 175.0	9/07 to 9/10	0.3% to 4.6%	Cash flow hedge

In August 2009, two of the Parent Company's floating-to-fixed interest rate swaps associated with its variable-interest rate borrowings expired. Such swaps had a notional amount of $250.0 million.

Changes in the fair value of the interest rate swaps and the related hedged items were recorded on the balance sheet with the offset recorded as interest expense. Cash flow hedges fix the interest rate paid on floating rate debt with the difference between the floating rate and fixed rate being recorded as an increase or decrease to interest expense. This combined activity resulted in an increase of interest expense of $16.2 million and $6.4 million for the years ended December 31, 2009 and 2008, respectively.

At times, we may use treasury lock derivative instruments to hedge the underlying U.S. treasury rates related to forecasted issuances of debt. As cash flow hedges, gains or losses on these instruments are recorded in OCI and amortized into earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. During 2008, we terminated treasury locks with a combined notional amount of $1.2 billion and recognized an aggregate loss of $43.9 million in OCI related to these terminations.

During the year ended December 31, 2009, we entered into four forward starting interest rate swaps to hedge the underlying benchmark interest payments related to the forecasted issuances of debt.

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Average Rate Locked	Accounting Treatment
Future debt offering	1 forward starting swap	$ 50.0	6/10 to 6/20	3.3%	Cash flow hedge
Future debt offering	3 forward starting swaps	$ 250.0	2/11 to 2/21	3.6%	Cash flow hedge

Forward starting interest rate swaps are used to hedge the underlying benchmark interest payments related to the forecasted issuances of debt. The fair market value of the forward starting swaps was $21.0

million at December 31, 2009. During January and February 2010, we entered into five additional forward starting swaps with a notional amount of $50.0 million each. The period hedged by these five forward starting swaps is February 2012 through February 2022.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as forwards, basis swaps, futures and options contracts. The following table summarizes our commodity derivative instruments outstanding at December 31, 2009:

	Volume (1)		**Accounting**
Derivative Purpose	**Current**	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	17.8 Bcf	n/a	Cash flow hedge
Forecasted NGL sales (4)	2.4 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	2.0 MMBbls	n/a	Cash flow hedge
NGLs inventory management	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	3.4 MMBbls	0.4 MMBbls	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	3.5 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	7.5 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	8.0 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas risk management activities (5) (6)	359.2 Bcf	33.9 Bcf	Mark-to-market
NGL risk management activities (6)	0.4 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	3.5 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	2.2 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives included in the long-term column is December 2012.
(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages. See the discussion below for the primary objective of this strategy.
(4) Excludes 5.4 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements under the FASB’s derivative and hedging guidance. The combination of these volumes with the 2.4 MMBbls reflected as derivatives in the table above results in a total of 7.8 MMBbls of hedged forecasted NGL sales volumes, which corresponds to the 17.8 Bcf of forecasted natural gas purchase volumes for PTR.
(5) Current and long-term volumes include approximately 109.5 and 12.6 billion cubic feet (“Bcf”), respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

Certain of our derivative instruments do not meet hedge accounting requirements; therefore, they are accounted for using mark-to-market accounting.

Our three predominant hedging strategies are hedging natural gas processing margins, hedging anticipated future sales of NGLs, refined products and crude oil associated with volumes held in inventory and hedging the fair value of natural gas in inventory. The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with the gas processing activities. We achieve this by using physical and financial instruments to lock in the prices of natural gas purchases used for PTR and NGL sales. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, achieved through the use of forward physical sales and commodity derivative instruments and (ii) the purchase of commodity derivative instruments with a notional amount determined by the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production. The objective of our NGL, refined products and crude oil sales hedging program is to hedge anticipated future sales of inventory by locking in the sales price through the use of forward physical sales and commodity derivative instruments. The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate. Prior to 2009, these derivative instruments were accounted for using mark-to-market accounting. Beginning with the first quarter of 2009, the long-term transactions (more than two months) are accounted for as cash flow hedges. Shorter term transactions are accounted for using mark-to-market accounting.

In 2008 and 2009 we were exposed to foreign currency exchange risk in connection with a term loan denominated in Japanese yen (see Note 12). We entered into this loan agreement in November 2008 and the loan matured in March 2009. The derivative instrument used to hedge this risk was accounted for as a cash flow hedge and was settled upon repayment of the loan.

At December 31, 2009, we had foreign currency derivative instruments outstanding with a notional amount of $4.1 million Canadian dollars. The fair market value of these instruments was an asset of $0.2 million at December 31, 2009.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At December 31, 2009, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $7.7 million, approximately $6.1 million of which was subject to a credit rating contingent feature. If our credit ratings were downgraded to Ba2/BB, approximately $1.1 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately $6.1 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as positions and prices fluctuate.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	December 31, 2009		December 31, 2008		December 31, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Derivative assets	$ 32.7	Derivative assets	$ 7.8	Derivative liabilities	$ 18.6	Derivative liabilities	$ 19.2
Interest rate derivatives	Other assets	31.8	Other assets	38.9	Other liabilities	6.7	Other liabilities	17.1
Total interest rate derivatives		64.5		46.7		25.3		36.3
Commodity derivatives	Derivative assets	52.0	Derivative assets	150.6	Derivative liabilities	62.6	Derivative liabilities	253.5
Commodity derivatives	Other assets	0.5	Other assets	--	Other liabilities	1.8	Other liabilities	0.2
Total commodity derivatives (1)		52.5		150.6		64.4		253.7
Foreign currency derivatives (2)	Derivative assets	0.2	Derivative assets	9.3	Derivative liabilities	--	Derivative liabilities	--
Total derivatives designated as hedging instruments		$ 117.2		$ 206.6		$ 89.7		$ 290.0
Derivatives not designated as hedging instruments								
Commodity derivatives	Derivative assets	$ 28.9	Derivative assets	$ 50.9	Derivative liabilities	$ 24.9	Derivative liabilities	$ 43.4
Commodity derivatives	Other assets	2.0	Other assets	--	Other liabilities	2.7	Other liabilities	--
Total commodity derivatives		30.9		50.9		27.6		43.4
Foreign currency derivatives	Derivative assets	--	Derivative assets	--	Derivative liabilities	--	Derivative liabilities	0.1
Total derivatives not designated as hedging instruments		$ 30.9		$ 50.9		$ 27.6		$ 43.5

(1) Represents commodity derivative transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the foreign currency exchange rate related to our Canadian NGL marketing subsidiary.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative	
		For Year Ended December 31,	
		2009	2008
Interest rate	Interest expense	$ (8.8)	$ 31.2
Commodity	Revenue	1.8	--
Total		$ (7.0)	$ 31.2

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item	
		For Year Ended December 31,	
		2009	2008
Interest rate	Interest expense	$ 3.2	$ (31.2)
Commodity	Revenue	(1.3)	--
Total		$ 1.9	$ (31.2)

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Statements of Consolidated Operations for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion)	
	For Year Ended December 31,	
	2009	2008
Interest rate derivatives	$ 12.5	$ (73.0)
Commodity derivatives – Revenue	(34.8)	(34.8)
Commodity derivatives – Operating costs and expenses	(144.8)	(135.4)
Foreign currency derivatives	(10.2)	9.3
Total	$ (177.3)	$ (233.9)

Derivatives in Cash Flow Hedging Relationships	Location	Amount of Loss Reclassified from AOCI into Income (Effective Portion)	
		For Year Ended December 31,	
		2009	2008
Interest rate derivatives	Interest expense	$ (26.4)	$ (5.5)
Commodity derivatives	Revenue	(61.0)	(56.7)
Commodity derivatives	Operating costs and expenses	(233.2)	(39.6)
Total		$ (320.6)	$ (101.8)

Derivatives in Cash Flow Hedging Relationships	Location	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative	
		For Year Ended December 31,	
		2009	2008
Interest rate derivatives	Interest expense	$ 1.4	$ (2.7)
Commodity derivatives	Revenue	0.2	--
Commodity derivatives	Operating costs and expenses	(0.1)	(1.7)
Foreign currency derivatives		--	(0.1)
Total		$ 1.5	$ (4.5)

Over the next twelve months, we expect to reclassify $21.3 million of AOCI attributable to interest rate derivative instruments into earnings as an increase to interest expense. Likewise, we expect to reclassify $0.8 million of AOCI attributable to commodity derivative instruments into earnings, $0.2 million as an increase in operating costs and expenses and $1.0 million as an increase in revenues.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative	
		For Year Ended December 31,	
		2009	2008
Commodity derivatives	Revenue	$ 40.7	$ 39.3
Commodity derivatives	Operating costs and expenses	--	(7.6)
Foreign currency derivatives	Other expense	(0.1)	(0.1)
Total		$ 40.6	$ 31.6

Fair Value Measurements

Fair value is defined 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. 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, including 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.

A three-tier hierarchy has been established 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 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 with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values primarily consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

§ 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, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions are: (i) observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over the counter. The fair values of these derivatives are based on observable price quotes for similar products and locations. The value of our interest rate derivatives are valued by using appropriate financial models with the implied forward London Interbank Offered Rate ("LIBOR") yield curve for the same period as the future interest swap settlements.

§ 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. Our Level 3 fair values largely consist of ethane, normal butane and natural gasoline-based contracts with a range of two to 12 months in term. We rely on price quotes from reputable brokers in the marketplace who publish price quotes on certain products. Whenever possible, we compare these prices to other reputable brokers for the same product in the same market. These prices, combined with our forward transactions, are used in our model to determine the fair value of such instruments.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at the dates indicated. 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, in addition to their placement within the fair value hierarchy levels.

	At December 31, 2009			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivative instruments	$ --	$ 64.5	$ --	$ 64.5
Commodity derivative instruments	14.6	34.4	34.4	83.4
Foreign currency derivative instruments	--	0.2	--	0.2
Total	$ 14.6	$ 99.1	$ 34.4	$ 148.1
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 25.3	$ --	$ 25.3
Commodity derivative instruments	17.1	46.2	28.7	92.0
Total	$ 17.1	$ 71.5	$ 28.7	$ 117.3

	At December 31, 2008			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivative instruments	$ --	$ 46.7	$ --	$ 46.7
Commodity derivative instruments	4.0	164.7	32.8	201.5
Foreign currency derivative instruments	--	9.3	--	9.3
Total	$ 4.0	$ 220.7	$ 32.8	$ 257.5
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 36.3	$ --	$ 36.3
Commodity derivative instruments	7.1	289.6	0.4	297.1
Foreign currency derivative instruments	--	0.1	--	0.1
Total	$ 7.1	$ 326.0	$ 0.4	$ 333.5

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities for the periods presented:

	For Year Ended December 31,	
	2009	2008
Balance, January 1	$ 32.4	$ (5.0)
Total gains (losses) included in:		
Net income (1)	27.0	(34.6)
Other comprehensive income (loss)	(21.8)	37.2
Purchases, issuances, settlements	(26.8)	34.8
Transfer out of Level 3	(5.1)	--
Balance, December 31	$ 5.7	$ 32.4

(1) There were unrealized losses of $5.2 million and gains of $0.2 million included in these amounts for the years ended December 31, 2009 and 2008, respectively.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). The following table presents the estimated fair value of certain assets carried on our Consolidated Balance Sheet by caption for which a nonrecurring change in fair value has been recorded during the year ended December 31, 2009:

	Level 3	Impairment Charges
Property, plant and equipment (see Note 8)	$ 29.6	$ 29.4
Intangible assets (see Note 11)	0.6	0.6
Goodwill (see Note 11)	--	1.3
Other current assets	1.2	2.2
Total	$ 31.4	$ 33.5

Using appropriate valuation techniques, we adjusted the carrying value of certain assets to $31.4 million and recorded non-cash impairment charges of $33.5 million during 2009. These charges are reflected in operating costs and expenses for the year ended December 31, 2009 and have been allocated to property, plant and equipment, intangible assets, goodwill and other current assets. During 2009, impairments primarily resulted from (i) reduced levels of throughput volumes at certain river terminals and the indefinite suspension of three new proposed river terminals, (ii) reduced throughput levels at a natural gas processing plant, (iii) the cancellation of a compressor station project and (iv) the determination that a storage cavern and certain marine barges were obsolete. Our fair value estimates were based primarily on an evaluation of the future cash flows associated with each asset.

Note 7. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31, 2009	December 31, 2008
Working inventory (1)	$ 466.4	$ 188.1
Forward sales inventory (2)	245.5	216.9
Total inventory	$ 711.9	$ 405.0

(1) Working inventory is comprised of inventories of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are either available-for-sale or used in the provision for services.

(2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts. In general, the increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets. The cash invested in forward sales NGL inventories is expected to be recovered within the next twelve months as physical delivery from inventory occurs.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-based prices during the month in which they are acquired.

Due to fluctuating commodity prices, we recognize LCM adjustments when the carrying value of our inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

- § Write-downs of NGL inventories are recorded as an expense related to our NGL marketing activities within our NGL Pipelines & Services business segment;

§ Write-downs of natural gas inventories are recorded as an expense related to our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment;

§ Write-downs of crude oil inventories are recorded as an expense related to our crude oil operations within our Onshore Crude Oil Pipelines & Services business segment; and

§ Write-downs of petrochemical, refined products and related inventories are recorded as an expense related to our petrochemical and refined products marketing activities or octane additive production business, as applicable, within our Petrochemical & Refined Products Services business segment.

To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 6 for a description of our commodity hedging activities.

The following table summarizes our cost of sales and LCM adjustment amounts for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Cost of sales (1)	$ 20,921.8	$ 31,204.8	$ 23,494.0
LCM adjustments	6.3	63.0	14.1

(1) Cost of sales is included in operating costs and expenses, as presented on our Statements of Consolidated Operations. The fluctuation in this amount year-to-year is primarily due to changes in energy commodity prices associated with our marketing activities.

Note 8. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	December 31, 2009	December 31, 2008
Plants and pipelines (1)	3-45 (5)	$ 17,681.9	$ 15,444.7
Underground and other storage facilities (2)	5-40 (6)	1,280.5	1,203.9
Platforms and facilities (3)	20-31	637.6	634.8
Transportation equipment (4)	3-10	60.1	50.9
Marine vessels	20-30	559.4	453.0
Land		82.9	76.5
Construction in progress		1,207.2	2,015.4
Total		21,509.6	19,879.2
Less accumulated depreciation		3,820.4	3,146.4
Property, plant and equipment, net		$ 17,689.2	$ 16,732.8

(1) Plants and pipelines include processing plants; 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; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; delivery facilities, 20-40 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

In August 2008, our wholly owned subsidiaries, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed the Texas Offshore Port System partnership ("TOPS"). Effective April 16, 2009, our wholly owned subsidiaries dissociated from TOPS. As a result, operating costs and expenses and net income for the year ended December 31, 2009 include a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment in TOPS through the date of dissociation and reflects our capital contributions to TOPS for construction in progress amounts.

TOPS was a consolidated subsidiary of ours prior to the dissociation. The effect of deconsolidation was to remove the accounts of TOPS, including Oiltanking's noncontrolling interest of $33.4 million, from our books and records, after reflecting the $68.4 million aggregate write-off of the investment. See Note 18 for information regarding expense amounts recognized during 2009 in connection with a settlement agreement involving TOPS.

We recorded $21.0 million, $4.3 million and $4.1 million of non-cash impairment charges within our Petrochemical & Refined Products Services segment, Onshore Natural Gas Pipelines & Services segment and NGL Pipelines & Services segment, respectively, related to plant, property and equipment during the year ended December 31, 2009. See Note 6 for additional information regarding impairment charges.

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Depreciation expense (1)	$ 678.1	$ 595.9	$ 515.7
Capitalized interest (2)	53.1	90.7	86.5

(1) Depreciation expense is a component of costs and expenses as presented in our Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, effective January 1, 2008, we revised the remaining useful lives of these assets, most notably the assets that constitute our Texas Intrastate System. This revision increased the remaining useful life of such assets to incorporate recent data showing that natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion as of January 1, 2008. On average, we extended the life of these assets by 3.1 years. As a result of this change in estimate, depreciation expense included in operating income and net income for the year ended December 31, 2008 decreased by approximately $20.0 million. Of this amount, $19.0 million was attributed to noncontrolling interest. The impact of this change on our earnings per unit was immaterial.

Asset Retirement Obligations

We have recorded AROs related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our AROs primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our AROs may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2007:

ARO liability balance, December 31, 2007	$ 42.2
Liabilities incurred	1.1
Liabilities settled	(8.2)
Revisions in estimated cash flows	4.7
Accretion expense	2.4
ARO liability balance, December 31, 2008	42.2
Liabilities incurred	0.5
Liabilities settled	(17.1)
Revisions in estimated cash flows	26.1
Accretion expense	3.1
ARO liability balance, December 31, 2009	$ 54.8

The increase in our ARO liability balance during 2009 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with our offshore facilities in the Gulf of Mexico. We incurred $14.6 million of costs through December 31, 2009 as a result of ARO settlement activities associated with certain pipeline laterals and a platform located in the Gulf of Mexico.

Property, plant and equipment at December 31, 2009 and 2008 includes $26.7 million and $11.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents forecasted accretion expense associated with our AROs for the years presented:

2010	2011	2012	2013	2014
$ 3.8	$ 3.7	$ 4.0	$ 4.3	$ 4.7

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2009 and 2008 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

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Note 9. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. We group our investments in unconsolidated affiliates according to the business segment to which they relate (see Note 14 for a general discussion of our business segments). The following table shows our investments in unconsolidated affiliates by business segment at the dates indicated:

	Ownership Percentage at December 31, 2009	December 31, 2009	December 31, 2008
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 32.6	$ 37.7
K/D/S Promix, L.L.C.	50%	48.9	46.4
Baton Rouge Fractionators LLC	32.2%	22.2	24.2
Skelly-Belvieu Pipeline Company, L.L.C.	49%	37.9	36.0
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	5.6	4.5
White River Hub, LLC	50%	26.4	21.4
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company	50%	178.5	186.2
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C.	36%	61.7	60.2
Cameron Highway Oil Pipeline Company (“Cameron Highway”)	50%	239.6	250.9
Deepwater Gateway, L.L.C.	50%	101.8	104.8
Neptune Pipeline Company, L.L.C.	25.7%	53.8	52.7
Nemo Gas Gathering Company, LLC (“Nemo”)	33.9 %	--	0.4
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	11.1	12.6
Centennial Pipeline LLC (“Centennial”)	50%	66.7	69.7
Other (2)	Varies	3.8	4.2
Other Investments:			
Energy Transfer Equity	17.5%	1,513.5	1,587.1
LE GP	40.6%	12.1	11.7
Total		$ 2,416.2	$ 2,510.7

(1) Evangeline refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. The following table summarizes the unamortized excess cost amounts by business segment at the dates indicated:

	December 31, 2009	December 31, 2008
NGL Pipelines & Services	$ 27.1	$ 28.0
Onshore Crude Oil Pipelines & Services	20.4	21.1
Offshore Pipelines & Service	17.3	18.6
Petrochemical & Refined Products Services	4.0	7.9
Other Investments (1)	1,573.0	1,609.6
Total	$ 1,641.8	$ 1,685.2

(1) The Parent Company’s initial investment in Energy Transfer Equity and LE GP exceeded its share of the historical cost of the underlying net assets of such investees by $1.67 billion. At December 31, 2009, this basis differential decreased to $1.57 billion (after taking into account related amortization amounts) and consisted of the following: $514.2 million attributed to fixed assets; $513.5 million attributed to the IDRs (an indefinite-life intangible asset) held by Energy Transfer Equity in the cash flows of ETP; $209.5 million attributed to amortizable intangible assets and $335.8 million attributed to equity method goodwill.

We amortize such excess cost amounts as a reduction in equity earnings in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services	$ 0.9	$ 0.5	$ 0.6
Onshore Crude Oil Pipelines & Services	0.7	0.7	0.7
Offshore Pipelines & Service	1.3	1.3	1.3
Petrochemical & Refined Products Services	3.9	4.3	5.3
Other Investments	36.6	34.3	26.7
Total	$ 43.4	$ 41.1	$ 34.6

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services	$ 11.3	$ 1.4	$ 7.1
Onshore Natural Gas Pipelines & Services	4.9	1.6	0.2
Onshore Crude Oil Pipelines & Services	9.3	11.7	2.6
Offshore Pipelines & Services	36.9	33.7	12.6
Petrochemical & Refined Products Services	(11.2)	(13.5)	(12.0)
Other Investments	41.1	31.3	3.1
Total	$ 92.3	$ 66.2	$ 13.6

NGL Pipelines & Services

At December 31, 2009, our investees included in our NGL Pipelines & Services segment own: (i) a natural gas processing facility and related assets located in south Louisiana, (ii) an NGL fractionation facility and related storage and pipeline assets located in south Louisiana, (iii) an NGL fractionation facility located in south Louisiana and (iv) a 572-mile pipeline that transports mixed NGLs to markets in southeast Texas.

During 2007, we sold an investment for approximately $156.0 million in cash and recognized a gain of $59.6 million, which is included in “Other, net” in our Statement of Consolidated Operations for the year ended December 31, 2007. The sale was required by the U.S. Federal Trade Commission in connection with ending its investigation into the acquisition of TEPPCO GP by privately held affiliates of EPCO in February 2005.

Onshore Natural Gas Pipelines & Services

At December 31, 2009, our investees included in our Onshore Natural Gas Pipelines & Services segment own: (i) a natural gas pipeline located in south Louisiana and (ii) a natural gas hub located in northwest Colorado that commenced operations in December 2008.

Onshore Crude Oil Pipelines & Services

At December 31, 2009, our investee included in our Onshore Crude Oil Pipelines & Services segment owns a pipeline that transports crude oil from a marine terminal located in Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal located in Texas City, Texas, to refineries in the Texas City and Houston, Texas areas.

Offshore Pipelines & Services

At December 31, 2009, our investees included in our Offshore Pipelines & Services segment own: (i) a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the

Gulf of Mexico for delivery to onshore locations in south Louisiana, (ii) a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas, (iii) a crude oil and natural gas platform that processes production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico and (iv) natural gas pipeline systems located in the Gulf of Mexico.

During 2007, Cameron Highway repaid two series of notes aggregating $415.0 million using cash contributions from its partners. We funded our 50% share of the capital contributions using borrowings under EPO's Multi-Year Revolving Credit Facility. Cameron Highway incurred a $14.1 million make-whole premium in connection with the repayment of its Series A notes.

Also during 2007, we evaluated our equity method investment in Nemo for impairment due to a decrease in throughput volumes primarily due to underperformance of certain fields and natural depletion. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of "Equity in income of unconsolidated affiliates" on our Consolidated Statement of Operations for the year ended December 31, 2007.

Petrochemical & Refined Products Services

At December 31, 2009, the investees included in our Petrochemical & Refined Products Services segment own: (i) a propylene fractionation facility located in south Louisiana, (ii) a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and (iii) an interstate refined products pipeline extending from the upper Texas Gulf Coast to central Illinois that effectively loops our refined products pipeline system providing incremental transportation capacity into Mid-continent markets.

Other Investments

This segment reflects the Parent Company's non-controlling ownership interests in Energy Transfer Equity and its general partner, LE GP. In May 2007, the Parent Company paid $1.65 billion to acquire 38,976,090 common units of Energy Transfer Equity and approximately 34.9% of the membership interests of LE GP. On January 22, 2009, the Parent Company acquired an additional 5.7% membership interest in LE GP for $0.8 million, which increased our total ownership in LE GP to 40.6%.

The business purpose of LE GP is to manage the affairs and operations of Energy Transfer Equity. LE GP has no separate business activities outside of those conducted by Energy Transfer Equity. LE GP owns a 0.31% general partner interest in Energy Transfer Equity and has no IDRs in the quarterly cash distributions of Energy Transfer Equity.

Energy Transfer Equity currently has no separate operating activities apart from those of ETP. Energy Transfer Equity's principal sources of distributable cash flow are its investments in the limited and general partner interests of ETP as follows:

§ Direct ownership of 62,500,797 ETP limited partner units representing approximately 35% of the total outstanding ETP units.

§ Indirect ownership of the general partner interest of ETP (representing a 1.9% interest as of December 31, 2009) and all associated IDRs held by ETP's general partner, of which Energy Transfer Equity owns 100% of the membership interests.

ETP is a publicly traded partnership owning and operating a diversified portfolio of midstream energy assets. ETP has pipeline operations in Arizona, Colorado, Louisiana, New Mexico and Utah, and owns the largest intrastate pipeline system in Texas. ETP's natural gas operations include intrastate natural gas gathering and transportation pipelines, natural gas treating and processing assets and three natural gas storage facilities located in Texas. ETP is also one of the three largest retail marketers of propane in the United States, serving more than one million customers across the country.

Summarized Combined Financial Information of Unconsolidated Affiliates

The consolidated balance sheet and results of operations information for the last two years for Energy Transfer Equity is summarized below:

	At December 31, 2009	At December 31, 2008
BALANCE SHEET DATA:		
Current assets	$ 1,268.0	$ 1,181.0
Property, plant and equipment, net	9,064.5	8,702.5
Other assets	1,828.0	1,186.4
Total assets	$ 12,160.5	$ 11,069.9
Current liabilities	$ 889.7	$ 1,208.9
Other liabilities	8,050.5	7,521.7
Combined equity	3,220.3	2,339.3
Total liabilities and combined equity	$ 12,160.5	$ 11,069.9

	For Year Ended December 31, 2009	For Year Ended December 31, 2008
INCOME STATEMENT DATA:		
Revenues	$ 5,417.3	$ 9,293.4
Operating income	1,110.4	1,098.9
Net income (1)	442.5	375.0

(1) Net income for Energy Transfer Equity represents net income attributable to the partners of Energy Transfer Equity.

Energy Transfer Equity's income statement data for the year ended December 31, 2007 is excluded from the table above due to Energy Transfer Equity changing its fiscal year end from August 31 to December 31 in November 2007. Energy Transfer Equity did not recast its consolidated financial data for prior fiscal periods; however, it did complete a four month transition period that began on September 1, 2007 and ended December 31, 2007. For the four months ended December 31, 2007, Energy Transfer Equity reported revenues of $2.35 billion, operating income of $316.7 million and net income attributable to Energy Transfer Equity of $92.7 million. For the year ended August 31, 2007, Energy Transfer Equity reported revenues of $6.79 billion, operating income of $809.3 million and net income attributable to Energy Transfer Equity of $319.4 million.

Equity earnings from our investment in Energy Transfer Equity for the year ended December 31, 2009 were $77.7 million, before $36.6 million of amortization of excess cost amounts. Equity earnings from this investment for the year ended December 31, 2008 were $65.6 million, before $34.3 million of amortization of excess cost amounts.

The combined balance sheet information for the last two years and results of operations data for the last three years for the remainder of our unconsolidated affiliates are summarized below:

	At December 31, 2009	At December 31, 2008
BALANCE SHEET DATA:		
Current assets	$ 201.0	$ 240.8
Property, plant and equipment, net	1,997.2	2,053.3
Other assets	36.4	23.1
Total assets	$ 2,234.6	$ 2,317.2
Current liabilities	$ 118.6	$ 165.9
Other liabilities	255.4	282.8
Combined equity	1,860.6	1,868.5
Total liabilities and combined equity	$ 2,234.6	$ 2,317.2

	For Year Ended December 31, 2009	2008	2007
INCOME STATEMENT DATA:			
Revenues	$ 738.1	$ 961.7	$ 794.1
Operating income	169.2	154.3	173.4
Net income	155.9	136.1	110.5

Note 10. Business Combinations

The following table presents our cash used for business combinations by segment for the periods indicated:

	For Year Ended December 31, 2009	2008	2007
NGL Pipelines & Services	$ 33.3	$ 77.0	$ 0.4
Onshore Natural Gas Pipelines & Services	0.8	125.2	35.5
Petrochemical & Refined Products Services	73.2	351.3	--
Total cash used for business combinations	$ 107.3	$ 553.5	$ 35.9

The following table depicts the fair value allocation of assets acquired and liabilities assumed for our business combinations for the periods indicated:

	For Year Ended December 31, 2009	2008	2007
Assets acquired in business combination:			
Current assets	$ 1.4	$ 6.6	$ --
Property, plant and equipment, net	115.9	549.6	44.5
Intangible assets	0.3	92.5	(8.5)
Other assets	(0.3)	0.4	--
Total assets acquired	117.3	649.1	36.0
Liabilities assumed in business combination:			
Current liabilities	0.3	(3.2)	--
Long-term debt	--	(2.6)	--
Other long-term liabilities	--	(109.5)	(1.2)
Total liabilities assumed	0.3	(115.3)	(1.2)
Total assets acquired plus liabilities assumed	117.6	533.8	34.8
Noncontrolling interest acquired	10.3	--	--
Fair value of 4,854,899 TEPPCO units	--	186.6	--
Total cash used for business combinations	107.3	553.5	35.9
Goodwill (1)	$ --	$ 206.3	$ 1.1

(1) See Note 11 for additional information regarding goodwill.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise GP Holdings L.P. and earnings per unit amounts would not have differed materially from those we actually reported for 2009, 2008 and 2007 due to the immaterial nature of our business combination transactions for those respective periods.

2009 Transactions

Our business combinations during 2009 primarily consisted of:

- the acquisition of certain rail and truck terminal facilities located in Mont Belvieu, Texas from Martin Midstream Partners LP for $23.7 million in cash;

- the acquisition of tow boats and tank barges primarily based in Miami, Florida, with additional assets located in Mobile, Alabama and Houston, Texas from TransMontaigne Product Services Inc. for $50.0 million in cash; and

- the acquisition of a majority interest in the Rio Grande Pipeline Company ("Rio Grande") purchased from HEP Navajo Southern L.P. for $32.8 million in cash. Rio Grande owns an NGL pipeline system in Texas.

2008 Transactions

Great Divide Gathering System Acquisition. In December 2008, one of our subsidiaries, Enterprise Gas Processing, LLC, purchased a 100% membership interest in Great Divide Gathering, LLC ("Great Divide") for cash consideration of $125.2 million. Great Divide was wholly owned by EnCana Oil & Gas ("EnCana").

The assets of Great Divide consist of a 32-mile natural gas gathering system, the Great Divide Gathering System, located in the Piceance Basin of northwest Colorado. The Great Divide Gathering System extends from the southern portion of the Piceance Basin, including production from EnCana's Mamm Creek field, to a pipeline interconnection with our Piceance Basin Gathering System. Volumes of natural gas originating on the Great Divide Gathering System are transported through our Piceance Creek Gathering System to our 1.7 Bcf/d Meeker natural gas treating and processing complex. A significant portion of these volumes are produced by EnCana and are dedicated to the Great Divide and Piceance Creek Gathering Systems for the life of the associated lease holdings.

Cenac and Horizon Acquisitions. In February 2008, TEPPCO entered the marine transportation business for refined products, crude oil and condensate through the purchase of assets from Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (collectively "Cenac"). The aggregate value of total consideration TEPPCO paid or issued to complete this business combination was $444.7 million, which consisted of $258.1 million in cash and 4,854,899 newly issued TEPPCO units. Additionally, TEPPCO assumed approximately $63.2 million of Cenac's debt in the transaction. TEPPCO 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. TEPPCO used a short-term credit facility to finance the cash portion of the acquisition price and to repay the $63.2 million of debt assumed in this transaction.

Also in February 2008, TEPPCO purchased related marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately held Houston-based company and an affiliate of Cenac, for $80.8 million in cash. In this transaction, TEPPCO acquired seven tow boats, 17 tank barges, rights to two tow boats under construction and the economic benefit of certain related commercial agreements. In April 2008, TEPPCO paid an additional $3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, TEPPCO paid an additional $3.8 million upon delivery of the second tow boat. These 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. TEPPCO used a short-term credit facility to finance this acquisition.

The results of operations related to these assets are included in our Statements of Consolidated Operations beginning at the date of acquisition.

Other Transactions. Other business combinations during 2008 primarily consisted of the acquisition of a natural gas gathering system located in the Piceance Basin of northwestern Colorado and additional interests in three consolidated NGL pipeline systems located along the U.S. Gulf Coast and southeastern United States.

2007 Transactions

Our expenditures for business combinations during the year ended December 31, 2007 primarily relate to the acquisition of a business with natural gas pipelines located in southeast Texas.

Note 11. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by segment at the dates indicated:

	December 31, 2009			December 31, 2008		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services: (1)						
Customer relationship intangibles	$ 237.4	$ (86.5)	$ 150.9	$ 237.4	$ (68.7)	$ 168.7
Contract-based intangibles	321.4	(156.7)	164.7	320.3	(137.6)	182.7
Segment total	558.8	(243.2)	315.6	557.7	(206.3)	351.4
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles (2)	372.0	(124.3)	247.7	372.0	(103.2)	268.8
Contract-based intangibles	565.3	(285.8)	279.5	565.3	(249.7)	315.6
Segment total	937.3	(410.1)	527.2	937.3	(352.9)	584.4
Onshore Crude Oil Pipelines & Services:						
Contract-based intangibles	10.0	(3.5)	6.5	10.0	(3.1)	6.9
Segment total	10.0	(3.5)	6.5	10.0	(3.1)	6.9
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(105.3)	100.5	205.8	(90.7)	115.1
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.1)	1.1
Segment total	207.0	(105.5)	101.5	207.0	(90.8)	116.2
Petrochemical & Refined Products Services: (3)						
Customer relationship intangibles	104.6	(18.8)	85.8	104.9	(13.8)	91.1
Contract-based intangibles	42.1	(13.9)	28.2	41.1	(8.2)	32.9
Segment total	146.7	(32.7)	114.0	146.0	(22.0)	124.0
Total all segments	$ 1,859.8	$ (795.0)	$ 1,064.8	$ 1,858.0	$ (675.1)	$ 1,182.9

(1) In 2008, we acquired $6.0 million of certain permits related to our Mont Belvieu complex and had $12.7 million of purchase price allocation adjustments related to San Felipe customer relationships from a 2007 business combination.
(2) In 2008, we acquired $9.8 million of customer relationships due to the Great Divide business combination.
(3) Amount includes a non-cash impairment charge of $0.6 million in 2009 related to certain intangible assets, see Note 6 for additional information.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services	$ 36.9	$ 40.7	$ 38.2
Onshore Natural Gas Pipelines & Services	57.2	61.7	64.4
Onshore Crude Oil Pipelines & Services	0.4	0.5	0.5
Offshore Pipelines & Services	14.7	16.9	19.3
Petrochemical & Refined Products Services	10.7	10.2	2.8
Total all segments	$ 119.9	$ 130.0	$ 125.2

The following table presents forecasted amortization expense associated with existing intangible assets for the years presented:

2010	2011	2012	2013	2014
$ 112.2	$ 105.0	$ 89.4	$ 82.4	$ 78.1

In general, our intangible assets fall within two categories – customer relationship and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases 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. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives.

At December 31, 2009, the carrying value of our customer relationship intangible assets was $584.9 million. The following information summarizes the significant components of this category of intangible assets:

§ San Juan Gathering System customer relationships – We acquired these customer relationships in connection with the GulfTerra Merger, which was completed on September 30, 2004. At December 31, 2009, the carrying value of this group of intangible assets was $220.8 million. These intangible assets are being amortized to earnings over their estimated economic life of 35 years through 2039. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying natural gas resource bases are expected to be consumed or otherwise used.

§ Offshore Pipeline & Platform customer relationships – We acquired these customer relationships in connection with the GulfTerra Merger. At December 31, 2009, the carrying value of this group of intangible assets was $100.5 million. These intangible assets are being amortized to earnings over their estimated economic lives, which range from 18 to 33 years (i.e., through 2022 to 2037). Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying crude oil and natural gas resource bases are expected to be consumed or otherwise used.

§ Encinal natural gas processing customer relationship – We acquired this customer relationship in connection with our Encinal acquisition in 2006. At December 31, 2009, the carrying value of this intangible asset was $89.3 million. This intangible asset is being amortized to earnings over its estimated economic life of 20 years through 2026. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefit of the underlying natural gas resource bases are expected to be consumed or otherwise used.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At December 31, 2009, the carrying value of our contract-based intangible assets was $479.9 million. The following information summarizes the significant components of this category of intangible assets:

§ Jonah Gas Gathering Company ("Jonah") natural gas gathering agreements – These intangible assets represent the value attributed to certain of Jonah's natural gas gathering contracts that were originally acquired by TEPPCO in 2001. At December 31, 2009, the carrying value of this group of intangible assets was $125.0 million. These intangible assets are being amortized to earnings using a units-of-production method based on throughput volumes on the Jonah system, which is estimated to extend through 2041.

§ Val Verde natural gas gathering agreements – These intangible assets represent the value attributed to certain natural gas gathering agreements associated with our Val Verde Gathering System that was originally acquired by TEPPCO in 2002. At December 31, 2009, the carrying value of these intangible assets was $98.4 million. These intangible assets are being amortized to earnings using a units-of-production method based on throughput volumes on the Val Verde Gathering System, which is estimated to extend through 2032.

§ Shell Processing Agreement – This margin-band/keepwhole processing agreement grants us the right to process Shell Oil Company's (or its assignee's) current and future natural gas production within the state and federal waters of the Gulf of Mexico. We acquired the Shell Processing Agreement in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the U.S. Gulf Coast. At December 31, 2009, the carrying value of this intangible asset was $105.9 million. This intangible asset is being amortized to earnings on a straight-line basis over its estimated economic life of 20 years through 2019.

§ Mississippi natural gas storage contracts – These intangible assets represent the value assigned by us to certain natural gas storage contracts associated with our Petal and Hattiesburg, Mississippi storage facilities. These facilities were acquired in connection with the GulfTerra Merger. At December 31, 2009, the carrying value of these intangible assets was $55.4 million. These intangible assets are being amortized to earnings on a straight-line basis over the remainder of their respective contract terms, which range from eight to 18 years (i.e. 2012 through 2022).

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year. The following table presents the changes in the carrying amount of goodwill for the periods presented:

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Totals
Balance at January 1, 2007	$ 224.8	$ 284.9	$ 303.0	$ 82.1	$ 917.3	$ 1,812.1
Goodwill related to acquisitions	1.2	--	--	--	--	1.2
Balance at December 31, 2007	226.0	284.9	303.0	82.1	917.3	1,813.3
Goodwill related to acquisitions	115.2	--	--	--	91.1	206.3
Balance at December 31, 2008	341.2	284.9	303.0	82.1	1,008.4	2,019.6
Impairment charges (1)	--	--	--	--	(1.3)	(1.3)
Balance at December 31, 2009 (2)	$ 341.2	$ 284.9	$ 303.0	$ 82.1	$ 1,007.1	$ 2,018.3

(1) See Note 6 for additional information regarding impairment charges recorded during year ended December 31, 2009.
(2) The total carrying amount of goodwill at December 31, 2009 is reflected net of $1.3 million of accumulated impairment charges.

Our goodwill impairment testing involves the determination of a reporting unit's fair value, which is predicated based on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. Based on our most recent goodwill impairment testing, each reporting unit's fair value was substantially in excess (a minimum of 10%) of its carrying value.

The following table summarizes components of our goodwill amounts by segment at the dates indicated:

	December 31,	
	2009	2008
NGL Pipelines & Services		
Acquisition of ownership interests in TEPPCO	$ 72.2	$ 72.2
GulfTerra Merger	23.8	23.8
Acquisition of Encinal	95.3	95.3
Acquisition of interest in Dixie	80.3	80.3
Acquisition of Great Divide	44.9	44.9
Acquisition of Indian Springs natural gas processing business	13.2	13.2
Other	11.5	11.5
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	279.9	279.9
Other	5.0	5.0
Onshore Crude Oil Pipeline & Services		
Acquisition of ownership interests in TEPPCO	288.8	288.8
Acquisition of crude oil pipeline and services business	14.2	14.2
Offshore Pipelines & Services		
GulfTerra Merger	82.1	82.1
Petrochemical & Refined Products Services		
Acquisition of ownership interests in TEPPCO	842.3	842.3
Acquisition of marine services businesses	90.4	90.4
Acquisition of Mont Belvieu propylene fractionation business	73.7	73.7
Other (1)	0.7	2.0
Total	$ 2,018.3	$ 2,019.6

(1) Includes a non-cash impairment charge of $1.3 million, see Note 6 for additional information.

Goodwill attributable to the acquisition of ownership interests in TEPPCO. As a result of our ownership of 100% of the limited and general partner interests of TEPPCO following the recently completed TEPPCO Merger, we applied push down accounting to the $1.2 billion of goodwill recorded by affiliates of EPCO (which are under common control with us) when they acquired 100% of the membership interests of TEPPCO GP and 4,400,000 TEPPCO limited partner units from a third-party in February 2005. The $1.2 billion in push down goodwill represents the excess of the purchase price paid by such affiliates to acquire ownership interests in TEPPCO in February 2005 over the respective fair value of assets acquired and liabilities assumed in the February 2005 transaction. Management attributes the $1.2 billion of goodwill to the future economic benefits we may realize from our ownership of TEPPCO, including anticipated commercial synergies and cost savings.

TEPPCO owns and operates an extensive network of assets that facilitate the movement, marketing, gathering and storage services of various commodities and energy-related products. TEPPCO's pipeline network is comprised of approximately 12,500 miles of pipelines that gather and transport refined products, crude oil, natural gas and NGLs, including one of the largest common carrier pipelines for refined products in the United States. TEPPCO also owns a marine services business that transports refined products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products via tow boats and tank barges. In addition, TEPPCO owns interests in the Seaway and Centennial pipeline systems.

Goodwill attributable to GulfTerra Merger. Goodwill recorded in connection with the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, we expected that various operating synergies could develop (such as reduced general and administrative costs and interest savings) that would result in improved financial results for the merged entity. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies in the United States, serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

Acquisition of Encinal. Management attributes goodwill recorded in connection with the Encinal acquisition to potential future benefits we may realize from our other south Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our south Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

Acquisition of Dixie and Great Divide. In 2008, we recorded goodwill in connection with our acquisition of the remaining third-party interest in Dixie and with the acquisition of Great Divide. The remaining ownership interests in Dixie were acquired from Amoco Pipeline Holding Company in August 2008. Management attributes the goodwill to future earnings growth on the Dixie Pipeline. Specifically, a 100% ownership interest in the Dixie Pipeline will increase our flexibility to pursue future opportunities. Great Divide was acquired from EnCana in December 2008. The Great Divide goodwill is attributable to management's expectations of future economics benefits derived from incremental natural gas processing margins and other downstream activities.

The Dixie and Great Divide goodwill amounts are recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

Acquisition of Cenac and Horizon. Also in 2008, we recorded goodwill in connection with our acquisition of marine services businesses, which are recorded as a part of the Petrochemical & Refined Products Services business segment due to management's belief of potential future economic benefits we expect to realize as a result of acquiring these assets.

Other goodwill amounts. The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our crude oil pipeline and services business originally purchased by TEPPCO in 2001, our purchase of a propylene fractionation business in February 2002 and our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing business in January 2005.

Note 12. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	December 31,	
	2009	2008
Parent Company debt obligations:		
EPE Revolver, variable-rate, due September 2012	$ 123.5	$ 102.0
$125.0 million Term Loan A, variable-rate, due September 2012	125.0	125.0
$850.0 Term Loan B, variable-rate, due November 2014 (1)	833.0	850.0
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable-rate, due November 2012	195.5	800.0
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010 (1)	54.0	54.0
Petal GO Zone Bonds, variable-rate, due August 2037	57.5	57.5
Yen Term Loan, 4.93% fixed-rate, due March 2009	--	217.6
Senior Notes B, 7.50% fixed-rate, due February 2011	450.0	450.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes F, 4.625% fixed-rate, due October 2009	--	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes K, 4.95% fixed-rate, due June 2010 (1)	500.0	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	--
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	--
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	--
Senior Notes S, 7.625% fixed-rate, due February 2012 (2)	490.5	--
Senior Notes T, 6.125% fixed-rate, due February 2013 (2)	182.5	--
Senior Notes U, 5.90% fixed-rate, due April 2013 (2)	237.6	--
Senior Notes V, 6.65% fixed-rate, due April 2018 (2)	349.7	--
Senior Notes W, 7.55% fixed-rate, due April 2038 (2)	399.6	--
TEPPCO senior debt obligations:		
TEPPCO Revolving Credit Facility, variable-rate, due December 2012	--	516.7
TEPPCO Senior Notes (2)	40.1	1,700.0
Duncan Energy Partners' debt obligations:		
DEP Revolving Credit Facility, variable-rate, due February 2011	175.0	202.0
DEP Term Loan, variable-rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	10,845.8	11,107.1
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068	682.7	682.7
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	285.8	--
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067 (2)	14.2	300.0
Total principal amount of senior and junior debt obligations	12,378.5	12,639.8
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments (see Note 6)	44.4	51.9
Unamortized discounts, net of premiums	(18.7)	(12.6)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 6)	23.7	35.8
Total other, non-principal amounts	49.4	75.1
Total long-term debt	$ 12,427.9	$ 12,714.9

(1) Long-term and current maturities of debt reflect the classification of such obligations at December 31, 2009. With respect to the $8.5 million due under Term Loan B, the Parent Company has the ability to use available credit capacity under the EPE Revolver to fund repayment of this amount. In addition, EPO has the ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility to fund the repayments of the Pascagoula MBFC Loan and Senior Notes K.

(2) Substantially all of TEPPCO debt obligations were exchanged for a corresponding series of new EPO notes in October 2009 in connection with the TEPPCO Merger.

Letters of Credit

At December 31, 2009, EPO had outstanding a $50.0 million letter of credit related to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities.

Subsidiary Guarantor Relationships

Enterprise Products Partners acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP Revolving Credit Facility and the DEP Term Loan Agreement. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. Additionally, TEPPCO's remaining debt obligations are non-recourse to Enterprise Products Partners.

Parent Company's Debt Obligations

The Parent Company consolidates the debt obligations of Enterprise Products Partners; however, the Parent Company does not have the obligation to make interest or debt payments with respect to such consolidated debt obligations.

EPE Interim Credit Facility. In May 2007, the Parent Company executed a $1.9 billion interim credit facility (the "EPE Interim Credit Facility") in connection with its acquisition of equity interests in Energy Transfer Equity and LE GP. The EPE Interim Credit Facility provided for a $200.0 million revolving credit facility and $1.7 billion of term loans. In August 2007, the Parent Company refinanced the $1.2 billion then outstanding under the EPE Interim Credit Facility using proceeds from its EPE August 2007 Credit Agreement.

EPE August 2007 Credit Agreement. The $1.2 billion EPE August 2007 Credit Agreement provided for a $200.0 million revolving credit facility (the "EPE Revolver"), a $125.0 million term loan ("Term Loan A") and an $850.0 million term loan (the "Term Loan A-2"). The EPE Revolver replaced the $200.0 million revolver associated with the EPE Interim Credit Facility and Term Loan A and Term Loan A-2 refinanced amounts then outstanding under the term loans associated with the EPE Interim Credit Facility. Amounts borrowed under the EPE Revolver and Term Loan A mature in September 2012. Amounts borrowed under Term Loan A-2 were refinanced in November 2007 with proceeds from a term loan (Term Loan B – described below) due November 2014.

Borrowings under the EPE August 2007 Credit Agreement are secured by the Parent Company's ownership of (i) 20,242,179 common units of Enterprise Products Partners, (ii) 100% of the membership interests in EPGP and (iii) 38,976,090 common units of Energy Transfer Equity.

The EPE Revolver may be used by the Parent Company to fund working capital and other capital requirements and for general partnership purposes. The EPE Revolver offers secured ABR loans ("ABR Loans") and Eurodollar loans ("Eurodollar Loans") each having different interest requirements.

ABR Loans bear interest at an alternative base rate (the "Alternative Base Rate") plus an applicable rate (the "Applicable Rate"). The Alternative Base Rate is a rate per annum equal to the greater of: (i) the annual interest rate publicly announced by Citibank, N.A. as its base rate in effect at its principal office in New York, New York (the "Prime Rate") in effect on such day and (ii) the federal funds effective rate in effect on such day plus 0.50%. The Applicable Rate for ABR Loans will be increased by an applicable margin ranging from 0% to 1.0% per annum. The Eurodollar Loans bear interest at a "LIBOR rate" (as defined in the August 2007 Credit Agreement) plus the Applicable Rate. The Applicable Rate for Eurodollar Loans will be increased by an applicable margin ranging from 1.00% to 2.50% per annum.

All borrowings outstanding under Term Loan A will, at the Parent Company's option, be made and maintained as ABR Loans or Eurodollar Loans, or a combination thereof. Any amount repaid under the Term Loan A may not be reborrowed.

In November 2007, the Parent Company executed a seven-year, $850 million senior secured term loan ("Term Loan B") in the institutional leveraged loan market. Proceeds from the Term Loan B were used to permanently refinance borrowings outstanding under the partnership's $850 million Term Loan A-2. The Term Loan B generally bears interest at LIBOR plus 2.25% and is scheduled to mature in November 2014. The Term Loan B is callable by the partnership at par.

The EPE August 2007 Credit Agreement contains various covenants related to the Parent Company's ability to incur certain indebtedness, grant certain liens, make fundamental structural changes, make distributions following an event of default and enter into certain restricted agreements. The credit agreement also requires the Parent Company to satisfy certain quarterly financial covenants.

EPO's Debt Obligations

Multi-Year Revolving Credit Facility. EPO has in place a $1.75 billion unsecured revolving credit facility, including the issuance of letters of credit ("Multi-Year Revolving Credit Facility"), which matures in November 2012. This credit facility has a term-out option that allows for EPO on the maturity date to convert the principal balance of all revolving loans then outstanding into a non-revolving one-year term loan. The credit facility allows EPO to request unlimited one-year extensions of the maturity date, subject to lender approval. The total amount of the bank commitments may be increased, without the consent of the lenders, by an amount not exceeding $500.0 million by adding one or more lenders to the facility and/or requesting that the commitments of existing lenders be increased.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a Eurodollar rate plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage. The applicable margins will be increased by 0.1% per annum for each day that the total outstanding loans and letter of credit obligations under the facility exceeds 50% of the total lender commitments. Also, if EPO exercises its term-out option at the maturity date, the applicable margin will increase by 0.125% per annum and, if immediately prior to such election, the total amount of outstanding loans and letter of credit obligations under the facility exceeds 50% of the total lender commitments, the applicable margin with respect to the term loan will increase by an additional 0.1% per annum.

The Multi-Year Revolving Credit Facility contains certain financial and other customary affirmative and negative covenants. The credit agreement also restricts EPO's ability to pay cash distributions to Enterprise Products Partners if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. Enterprise Products Partners has guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

Pascagoula MBFC Loan. This loan, from the Mississippi Business Finance Corporation ("MBFC"), matured on March 1, 2010 and was repaid.

Petal GO Zone Bonds. In August 2007, Petal Gas Storage, L.L.C. ("Petal"), a wholly owned subsidiary of EPO, borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal and the MBFC. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by a bank that expires in August 2014. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt ("GO Zone") bonds to various third parties. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of 30 years.

Petal MBFC Loan. In August 2007, Petal entered into a loan agreement and a promissory note with the MBFC under which Petal may borrow up to $29.5 million. On the same date, the MBFC issued taxable bonds to EPO in the maximum amount of $29.5 million. At December 31, 2009, there was $8.9 million outstanding under the loan and the bonds. The promissory note and the taxable bonds have identical terms. The loan and bonds and the related interest expense and income amounts are netted in preparing our consolidated financial statements.

Japanese Yen Term Loan. In November 2008, EPO executed the Yen Term Loan in the amount of approximately 20.7 billion yen (approximately $217.6 million U.S. Dollar equivalent on the closing date). EPO entered into foreign exchange currency swaps that effectively converted the loan into a U.S. Dollar loan with a fixed interest rate of approximately 4.93%. The Yen Term Loan matured on March 30, 2009. Additionally, EPO executed a forward purchase exchange (yen principal and interest due) at an exchange rate of 94.515 to eliminate foreign exchange risk, resulting in a payment of US$221.6 million on March 30, 2009.

364-Day Revolving Credit Facility. From November 2008 through June 2009, EPO had a $375.0 million standby credit facility. The facility was never utilized and was terminated in June 2009 under its terms as a result of issuing senior notes.

Senior Notes. EPO's senior fixed-rate notes are unsecured obligations of EPO and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. EPO's borrowings under these notes are non-recourse to EPGP. Enterprise Products Partners has guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Enterprise Products Partners' guarantee of such notes is non-recourse to EPGP. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

In June 2009, EPO issued $500.0 million in principal amount of 3-year senior unsecured notes (Senior Notes P) at 99.95% of their principal amount. In October 2009, EPO issued: (i) $500.0 million in principal amount of 10-year unsecured notes (Senior Notes Q) at 99.355% of their principal amount and (ii) $600.0 million in principal amount of 30-year unsecured notes (Senior Notes R) at 99.386% of their principal amount. Net proceeds from the issuance of these senior notes were used (i) to repay amounts borrowed under a $200.0 million term loan that EPO entered into during April 2009, (ii) to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, (iii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iv) for general partnership purposes.

In connection with the TEPPCO Merger, EPO offered to exchange all of TEPPCO's outstanding senior notes for a corresponding series of new EPO senior notes. The exchanges were completed on October 27, 2009 as follows:

TEPPCO Notes Exchanged	Corresponding Series of New EPO Notes	Aggregate Principal Amount	Principal Amount Exchanged	Principal Amount Remaining
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	Senior Notes S, 7.625% fixed-rate, due February 2012	$ 500.0	$ 490.5	$ 9.5
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	Senior Notes T, 6.125% fixed-rate, due February 2013	200.0	182.5	17.5
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	Senior Notes U, 5.90% fixed-rate, due April 2013	250.0	237.6	12.4
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	Senior Notes V, 6.65% fixed-rate, due April 2018	350.0	349.7	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	Senior Notes W, 7.55% fixed-rate, due April 2038	400.0	399.6	0.4
		$ 1,700.0	$ 1,659.9	$ 40.1

Junior Subordinated Notes. EPO's payment obligations under its junior notes are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). Enterprise Products Partners has guaranteed repayment of amounts due under these notes through an unsecured and subordinated guarantee. The indenture agreement governing these notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither Enterprise Products Partners nor EPO can declare or make any distributions to any of its respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to the junior notes. Each series of our subordinated junior notes are ranked equally with each other. Generally, each series of junior subordinated notes are not redeemable by EPO without payment of a make-whole premium while the notes bear interest at a fixed annual rate.

In connection with the issuance of each series of junior subordinated notes, EPO entered into separate Replacement Capital Covenants in favor of covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

In connection with the TEPPCO Merger, EPO offered to exchange TEPPCO's outstanding junior subordinated notes for a corresponding series of new EPO junior subordinated notes. The exchange was completed on October 27, 2009:

TEPPCO Notes Exchanged	Corresponding Series of New EPO Notes	Aggregate Principal Amount	Principal Amount Exchanged	Principal Amount Remaining
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067	$ 300.0	$ 285.8	$ 14.2

The following table summarizes the interest rate terms of our junior subordinated notes:

Series	Fixed Annual Interest Rate	Variable Annual Interest Rate Thereafter
Junior Subordinated Notes A	8.375% through August 2016 (1)	3-month LIBOR rate + 3.708% (4)
Junior Subordinated Notes B	7.034% through January 2018 (2)	Greater of: (i) 3-month LIBOR rate + 2.68% or (ii) 7.034% (5)
Junior Subordinated Notes C	7.00% through June 2017 (3)	3-month LIBOR rate + 2.778% (6)

(1) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2007.
(2) Interest is payable semi-annually in arrears in January and July of each year, which commenced in January 2008.
(3) Interest is payable semi-annually in arrears in June and December of each year, which commenced in December 2009.
(4) Interest is payable quarterly in arrears in February, May, August and November of each year commencing in November 2016.
(5) Interest is payable quarterly in arrears in January, April, July and October of each year commencing in April 2018.
(6) Interest is payable quarterly in arrears in March, June, September and December of each year commencing in June 2017.

TEPPCO's Debt Obligations

TEPPCO Revolving Credit Facility. Upon consummation of the TEPPCO Merger, EPO repaid and terminated all of the outstanding indebtedness under the TEPPCO Revolving Credit Facility.

TEPPCO Senior Notes. As previously discussed, on October 27, 2009, $1.66 billion of the TEPPCO Senior Notes were exchanged for an equal amount of new EPO Senior Notes. In addition to the debt exchange, substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO Senior Notes were eliminated through amendments that became effective on October 26, 2009.

TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. (collectively, the "Subsidiary Guarantors") acted as guarantors of TEPPCO's outstanding senior notes through November 2009. The subsidiary guarantees were terminated in November 2009.

TEPPCO Junior Subordinated Notes. As discussed above, on October 27, 2009, $285.8 million of the TEPPCO Junior Subordinated Notes were exchanged for an equal amount of new EPO Junior Subordinated Notes. In addition to the debt exchange, substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO Junior Subordinated Notes were eliminated through amendments that became effective on October 26, 2009.

The Subsidiary Guarantors also acted as guarantors, on a junior subordinated basis, of TEPPCO's outstanding junior subordinated notes through November 2009. These subsidiary guarantees were terminated in November 2009.

The terms and provisions of the TEPPCO's Junior Subordinated Notes are similar to each series of EPO's junior subordinated notes. For example, they: (i) are general unsecured subordinated obligations, (ii) allow interest payments to be deferred for multiple periods of up to ten consecutive years and (iii) are subordinated in right of payment to all existing and future senior indebtedness. The maturity date, the interest rate and the interest payment due dates are the identical to EPO's Junior Subordinated Notes C as discussed above.

In connection with the issuance of the TEPPCO Junior Subordinated Notes, TEPPCO and its Subsidiary Guarantors entered into a Replacement Capital Covenant in favor of the covered debt holders (as defined in the underlying documents) pursuant to which TEPPCO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities. The Replacement Capital Covenant is not a term of the governing indenture or the junior subordinated notes.

Duncan Energy Partners' Debt Obligations

Enterprise Products Partners consolidates the debt of Duncan Energy Partners with that of its own; however, Enterprise Products Partners does not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

DEP Revolving Credit Facility. Duncan Energy Partners has in place a $300 million unsecured revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. This credit facility will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date, which is February 2011 (subject to certain restrictions). The revolving credit facility is available to pay distributions to its partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed $150.0 million, by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) a Eurodollar rate, plus the applicable Eurodollar margin (as defined in the credit agreement), (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

The Duncan Energy Partners' credit facility contains certain financial and other customary affirmative and negative covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

DEP Term Loan. In April 2008, Duncan Energy Partners entered into a standby term loan agreement consisting of commitments for up to a $300.0 million senior unsecured term loan. Subsequently, commitments under this agreement decreased to $282.3 million due to bankruptcy of one of the lenders. Duncan Energy Partners borrowed the full amount of $282.3 million on December 8, 2008 in connection with the acquisition of equity interests in midstream energy businesses.

Duncan Energy Partners may prepay loans under the term loan agreement at any time, subject to prior notice in accordance with the credit agreement. Loans may also be payable earlier in connection with an event of default.

Loans under the term loan agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate loans or Eurodollar loans. The term loan agreement contains certain financial and other customary affirmative and negative covenants.

Dixie Revolving Credit Facility

Dixie's debt obligation consisted of a senior, unsecured revolving credit facility having a borrowing capacity of $28.0 million. This credit facility was terminated in January 2009.

Canadian Debt Obligation

In May 2007, Canadian Enterprise Gas Products, Ltd., a wholly owned subsidiary of EPO, entered into a $30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings. The credit facility contains customary covenants and events of default. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2009, there were no debt obligations outstanding under this credit facility.

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2009.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligations during the year ended December 31, 2009:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPE Revolver	1.23% to 3.25%	1.63%
EPE Term Loan A	1.23% to 3.20%	1.63%
EPE Term Loan B	2.48% to 6.77%	3.00%
EPO Multi-Year Revolving Credit Facility	0.73% to 3.25%	0.95%
TEPPCO Revolving Credit Facility	0.75% to 3.25%	0.88%
DEP Revolving Credit Facility	0.81% to 2.74%	1.48%
DEP Term Loan	0.93% to 2.93%	1.15%
Petal GO Zone Bonds	0.21% to 2.75%	0.60%

Consolidated Debt Maturity Table

The following table presents contractually scheduled maturities of our consolidated debt obligations for the next five years, and in total thereafter.

		Scheduled Maturities of Debt					
	Total	2010 (1)	2011	2012	2013	2014	After 2014
Revolving Credit Facilities	$ 494.0	$ --	$ 175.0	$ 319.0	$ --	$ --	$ --
Senior Notes	9,000.0	500.0	450.0	1,000.0	1,200.0	1,150.0	4,700.0
Term Loans	1,240.3	8.5	290.8	133.5	8.5	799.0	--
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Other	111.5	54.0	--	--	--	--	57.5
Total	$ 12,378.5	$ 562.5	$ 915.8	$ 1,452.5	$ 1,208.5	$ 1,949.0	$ 6,290.2

(1) Long-term and current maturities of debt reflect the classification of such obligations on our Consolidated Balance Sheet at December 31, 2009 after taking into consideration EPO's ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility and the Parent Company's ability to use available borrowing capacity under the EPE Revolver.

Debt Obligations of Unconsolidated Affiliates

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) the ownership interest in each entity at December 31, 2009, (ii) total debt of each unconsolidated affiliate at December 31, 2009 (on a 100% basis to the unconsolidated affiliate) and (iii) the corresponding scheduled maturities of such debt.

			Scheduled Maturities of Debt					
	Ownership Interest	Total	2010	2011	2012	2013	2014	After 2014
Poseidon	36%	$ 92.0	$ --	$ 92.0	$ --	$ --	$ --	$ --
Evangeline	49.5%	10.7	3.2	7.5	--	--	--	--
Centennial	50%	120.0	9.1	9.0	8.9	8.6	8.6	75.8
Total		$ 222.7	$ 12.3	$ 108.5	$ 8.9	$ 8.6	$ 8.6	$ 75.8

The credit agreements of these unconsolidated affiliates include customary covenants, including financial covenants. These businesses were in compliance with such financial covenants at December 31, 2009. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution is scheduled to be paid.

The following information summarizes the significant terms of the debt obligations of these unconsolidated affiliates at December 31, 2009:

Poseidon. At December 31, 2009, Poseidon's debt obligations consisted of $92.0 million outstanding under its $150.0 million variable-rate revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets. The weighted-average variable interest rates charged on this debt at December 31, 2009 and 2008 were 1.88% and 4.31%, respectively.

Evangeline. At December 31, 2009, Evangeline's debt obligations consisted of: (i) $3.2 million in principal amount of 9.90% fixed-rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable due in 2011. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment; proceeds from a gas sales contract and by a debt service reserve requirement.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the subordinated note until such time as the Series B noteholders are either fully cash secured through debt service accounts or have been completely repaid.

Variable-rate interest accrues on the subordinated note at LIBOR plus 0.5%. The weighted-average variable interest rates charged on this note at December 31, 2009 and 2008 were 1.59% and 3.62%, respectively. Accrued interest payable related to the subordinated note was $10.2 million and $9.8 million at December 31, 2009 and 2008, respectively.

Centennial. At December 31, 2009, Centennial's debt obligations consisted of $120.0 million borrowed under a master shelf loan agreement through two private placements, with interest rates ranging from 7.99% to 8.09%. 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.

We and our joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial were to default on its debt obligations, the estimated payment obligation would be $60.0 million based on amounts outstanding at December 31, 2009. We recognized a liability of $8.4 million for our share of the Centennial debt guaranty at December 31, 2009.

Note 13. Equity and Distributions

Our Units represent limited partner interests, which give the holders thereof the right to participate in cash distributions and to exercise the other rights or privileges available to them under our First Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement").

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of the Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to GAAP-based equity amounts presented in our consolidated financial statements. Earnings and cash distributions are allocated to holders of our Units in accordance with their respective percentage interests.

Registration Statement

The Parent Company has a universal shelf registration statement on file with the SEC that allows it to issue an unlimited amount of debt and equity securities for general partnership purposes. As of December 31, 2009, the Parent Company had not issued any securities under its registration statement.

Class B and C Units

In May 2007, we issued an aggregate of 14,173,304 Class B Units and 16,000,000 Class C Units to private company affiliates of EPCO in connection with their contribution of 4,400,000 common units representing limited partner interest of TEPPCO and 100% of the general partner interest of TEPPCO GP.

On July 12, 2007, all of the outstanding 14,173,304 Class B Units were converted into Units on a one-to-one basis. On February 1, 2009, all of the outstanding 16,000,000 Class C Units were converted to Units on a one-to-one basis. For financial accounting purposes, the Class C Units were not allocated any portion of net income until their conversion into Units. In addition, the Class C Units were non-participating in current or undistributed earnings prior to conversion. The Units into which the Class C Units were converted were eligible to receive cash distributions beginning with the distribution paid in May 2009.

Prior to February 1, 2009, the Class C Units (i) entitled the holder to the allocation of taxable income, gain, loss, deduction and credit to the same extent as such tax amounts were allocated to the holder if the Class C Units were converted and outstanding Units and (ii) were non-voting, except that, the Class C Units were entitled to vote as a separate class on any matter that adversely affected the rights or preferences of the Class C Units in relation to other classes of partnership interests (including as a result of a merger or consolidation) or as required by law. The approval of a majority of the Class C Units was required to approve any matter for which the holders of the Class C Units were entitled to vote as a separate class.

Private Placement of Parent Company Units

On July 17, 2007, the Parent Company completed a private placement of 20,134,220 Units to third-party investors at $37.25 per Unit. The net proceeds of this private placement, after giving effect to placement agent fees, were approximately $739.0 million. The net proceeds were used to repay certain principal amounts outstanding under the EPE Interim Credit Facility and related accrued interest. Effective October 5, 2007, these Units were registered for resale.

Unit History

The following table summarizes changes in our outstanding Units since December 31, 2006:

	Units	Class B Units	Class C Units
Balance, December 31, 2006	88,884,116	14,173,304	16,000,000
Conversion of Class B Units to Units in July 2007	14,173,304	(14,173,304)	--
Units issued in connection private placement in July 2007	20,134,220	--	--
Balance, December 31, 2007 and 2008	123,191,640	--	16,000,000
Conversion of Class C Units to Units in February 2009	16,000,000	--	(16,000,000)
Balance, December 31, 2009	139,191,640	--	--

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2006:

	Units	Class B Units	Class C Units	Total
Balance, December 31, 2006	$ 681.0	$ 357.1	$ 380.7	$ 1,418.8
Net income	75.6	33.4	--	109.0
Operating lease expenses paid by EPCO	0.1	--	--	0.1
Cash distributions paid to partners	(159.0)	--	--	(159.0)
Distributions to former owners	--	(29.8)	--	(29.8)
Conversion of Class B Units to Units	360.7	(360.7)	--	--
Net cash proceeds from issuance of Units	739.4	--	--	739.4
Amortization of equity awards	0.6	--	--	0.6
Balance, December 31, 2007	1,698.4	--	380.7	2,079.1
Net income	164.0	--	--	164.0
Operating lease expenses paid by EPCO	0.1	--	--	0.1
Cash distributions paid to partners	(213.1)	--	--	(213.1)
Amortization of equity awards	1.1	--	--	1.1
Balance, December 31, 2008	1,650.5	--	380.7	2,031.2
Net income	204.1	--	--	204.1
Cash distributions paid to partners	(266.7)	--	--	(266.7)
Conversion of Class C Units to Units	380.7	--	(380.7)	--
Amortization of equity awards	3.8	--	--	3.8
Balance, December 31, 2009	$ 1,972.4	$ --	$ --	$ 1,972.4

Distributions to Partners

The Parent Company's cash distribution policy is consistent with the terms of its Partnership Agreement, which requires it to distribute its available cash (as defined in our Partnership Agreement) to its partners no later than 50 days after the end of each fiscal quarter. The quarterly cash distributions are not cumulative.

The following table presents the Parent Company's declared quarterly cash distribution rates per Unit since the first quarter of 2008 and the related record and distribution payment dates. The quarterly cash distribution rates per Unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 50 days after the end of such fiscal quarter.

	Cash Distribution History		
	Distribution per Unit	Record Date	Payment Date
2008			
1st Quarter	$ 0.425	Apr. 30, 2008	May 8, 2008
2nd Quarter	$ 0.440	Jul. 31, 2008	Aug. 8, 2008
3rd Quarter	$ 0.455	Oct. 31, 2008	Nov. 13, 2008
4th Quarter	$ 0.470	Jan. 30, 2009	Feb. 10, 2009
2009			
1st Quarter	$ 0.485	Apr. 30, 2009	May 11, 2009
2nd Quarter	$ 0.500	Jul. 31, 2009	Aug. 10, 2009
3rd Quarter	$ 0.515	Oct. 30, 2009	Nov. 6, 2009
4th Quarter	$ 0.530	Jan. 29, 2010	Feb. 5, 2010

Accumulated Other Comprehensive Loss

AOCI primarily includes the effective portion of the gain or loss on derivative instruments designated and qualified as a cash flow hedge, foreign currency adjustments and minimum pension liability adjustments. Amounts accumulated in OCI from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in AOCI must be immediately reclassified.

The following table presents the components of AOCI at the dates indicated:

	At December 31,	
	2009	2008
Commodity derivative instruments (1)	$ 0.5	$ (114.1)
Interest rate derivative instruments (1)	(27.6)	(66.5)
Foreign currency derivative instruments (1)	0.4	10.6
Foreign currency translation adjustment (2)	0.8	(1.3)
Pension and postretirement benefit plans	(0.8)	(0.8)
Proportionate share of other comprehensive loss of unconsolidated affiliates, primarily Energy Transfer Equity	(11.2)	(13.7)
Subtotal	(37.9)	(185.8)
Amount attributable to noncontrolling interest	4.6	132.6
Total AOCI in partners' equity	$ (33.3)	$ (53.2)

(1) See Note 6 for additional information regarding these components of AOCI.
(2) Relates to transactions of Enterprise Products Partners' Canadian NGL marketing subsidiary.

Noncontrolling Interest

Prior to the completion of the TEPPCO Merger, effective October 26, 2009, we accounted for the former owners' interest in TEPPCO and TEPPCO GP as noncontrolling interest. Under this method of presentation, all pre-merger revenues and expenses of TEPPCO and TEPPCO GP are included in net income, and the former owners' share of the income of TEPPCO and TEPPCO GP is allocated to net income attributable to noncontrolling interest. In addition, the former owners' share of the net assets of TEPPCO and TEPPCO GP are presented as noncontrolling interest, a component of equity, on our Consolidated Balance Sheets.

The following table presents the components of noncontrolling interest as presented on our Consolidated Balance Sheets at the dates indicated:

	At December 31, 2009	At December 31, 2008
Limited partners of Enterprise Products Partners:		
Third-party owners of Enterprise Products Partners (1)	$ 7,001.6	$ 5,010.6
Related party owners of Enterprise Products Partners (2)	1,003.6	347.7
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (1)	414.3	281.1
Related party owners of Duncan Energy Partners (2)	1.7	--
Former owners of TEPPCO (3)	--	2,126.5
Joint venture partners (4)	117.4	148.1
AOCI attributable to noncontrolling interest	(4.6)	(132.6)
Total noncontrolling interest on consolidated balance sheets	$ 8,534.0	$ 7,781.4

(1) Consists of non-affiliate public unitholders of Enterprise Products Partners and Duncan Energy Partners. The increase in noncontrolling interest between periods for these entities is primarily due to equity offerings.
(2) Consists of unitholders of Enterprise Products Partners and Duncan Energy Partners that are related party affiliates of the Parent Company. This group is primarily comprised of EPCO and certain of its private company consolidated subsidiaries.
(3) Represents former ownership interests in TEPPCO and TEPPCO GP (see Note 1 “Basis of Presentation”). This amount excludes AOCI attributable to former owners of TEPPCO.
(4) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole, Tri-States Pipeline L.L.C., Independence Hub LLC and Wilprise Pipeline Company LLC. The balance at December 31, 2008 included $35.6 million related to Oiltanking’s ownership interest in TOPS, from which our subsidiaries dissociated in April 2009 (see Note 8).

The following table presents the components of net income attributable to noncontrolling interest as presented on our Statements of Consolidated Operations for the periods indicated:

	For Year Ended December 31, 2009	2008	2007
Limited partners of Enterprise Products Partners (1)	$ 825.5	$ 786.5	$ 404.8
Limited partners of Duncan Energy Partners (1)	31.3	17.3	13.8
Former owners of TEPPCO (2)	53.0	153.3	217.6
Joint venture partners	26.4	24.0	16.8
Total	$ 936.2	$ 981.1	$ 653.0

(1) Represents the allocation of Enterprise Products Partners’ and Duncan Energy Partners’ earnings to their respective unitholders, other than the Parent Company.
(2) Represents the allocation of earnings to the former owners of TEPPCO.

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Statements of Consolidated Cash Flows for the periods indicated:

	For Year Ended December 31, 2009	2008	2007
Cash distributions paid to noncontrolling interests:			
Limited partners of Enterprise Products Partners	$ 1,038.1	$ 865.7	$ 807.5
Limited partners of Duncan Energy Partners	33.7	24.8	15.8
Limited partners of TEPPCO	218.4	260.5	234.0
Joint venture partners	31.9	31.1	16.6
Total cash distributions paid to noncontrolling interests	$ 1,322.1	$ 1,182.1	$ 1,073.9
Cash contributions from noncontrolling interests:			
Limited partners of Enterprise Products Partners	$ 875.4	$ 135.0	$ 68.0
Limited partners of Duncan Energy Partners	137.4	--	290.5
Limited partners of TEPPCO	3.5	275.8	1.7
Joint venture partners	(2.1)	35.6	12.5
Total cash contributions received from noncontrolling interests	$ 1,014.2	$ 446.4	$ 372.7

Distributions paid to the limited partners of Enterprise Products Partners, Duncan Energy Partners and former owners of TEPPCO primarily represent the quarterly cash distributions paid by these entities to their unitholders, excluding those paid to the Parent Company.

Contributions received from limited partners of Enterprise Products Partners, Duncan Energy Partners and TEPPCO primarily represent net cash proceeds each entity received from common unit offerings and distribution reinvestment plans, excluding those received from the Parent Company. During 2009, Enterprise Products Partners issued an aggregate of 36,950,014 of its common units, which generated net cash proceeds of approximately $911.0 million. Additionally, during 2009 Duncan Energy Partners issued an aggregate 8,943,400 of its common units, which generated net cash proceeds of approximately $137.4 million. During 2007, Duncan Energy Partners received approximately $291.0 million of net cash proceeds in connection with its initial public offering. During 2008, TEPPCO sold 9,200,000 of its units in an underwritten equity offering, which generated net cash proceeds of $257.0 million.

Note 14. Business Segments

We have six reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Onshore Crude Oil Pipelines & Services, Offshore Pipelines & Services, Petrochemical & Refined Products Services and Other Investments. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash consolidated asset impairment charges; (iii) operating lease expenses for which we do not have the payment obligation; (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a standalone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas, refined products and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Additionally, our use of the Centennial pipeline, which loops the refined products pipeline system between Beaumont, Texas and southern Illinois, 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. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Substantially all of our consolidated revenues are earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL, refined products and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas, Louisiana, and onshore in Colorado; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); (iii) the Midwestern and northeastern United States; and (iv) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and Oklahoma City, Oklahoma and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (which are a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Enterprise Products Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Enterprise Products Partners.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Revenues	$ 25,510.9	$ 35,469.6	$ 26,713.8
Less: Operating costs and expenses	(23,565.8)	(33,618.9)	(25,402.1)
Add: Equity in income of unconsolidated affiliates	92.3	66.2	13.6
Depreciation, amortization and accretion in operating costs and expenses (1)	809.3	725.4	647.9
Impairment charges in operating costs and expenses	33.5	--	--
Operating lease expenses paid by EPCO	0.7	2.0	2.1
Gain from asset sales and related transactions in operating costs and expenses (2)	--	(4.0)	(7.8)
Total segment gross operating margin	$ 2,880.9	$ 2,640.3	$ 1,967.5

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Statements of Consolidated Cash Flows.
(2) Amount is a component of "Gain from asset sales and related transactions" as presented on the Statements of Consolidated Cash Flows.

The following table shows a reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Total segment gross operating margin	$ 2,880.9	$ 2,640.3	$ 1,967.5
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(809.3)	(725.4)	(647.9)
Impairment charges in operating costs and expenses	(33.5)	--	--
Operating lease expenses paid by EPCO	(0.7)	(2.0)	(2.1)
Gain from asset sales and related transactions in operating costs and expenses	--	4.0	7.8
General and administrative costs	(182.8)	(144.8)	(131.9)
Operating income	1,854.6	1,772.1	1,193.4
Other expense, net	(689.0)	(596.0)	(415.6)
Income before provision for income taxes	$ 1,165.6	$ 1,176.1	$ 777.8

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Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments							
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:								
Year ended December 31, 2009	$ 11,928.3	$ 2,938.7	$ 7,191.2	$ 332.9	$ 2,520.8	$ --	$ --	$ 24,911.9
Year ended December 31, 2008	14,715.8	3,407.2	12,763.8	260.3	3,307.1	--	--	34,454.2
Year ended December 31, 2007	12,149.2	2,044.0	9,103.7	222.6	2,609.1	--	--	26,128.6
Revenues from related parties:								
Year ended December 31, 2009	380.7	211.2	(0.2)	7.0	0.3	--	--	599.0
Year ended December 31, 2008	598.0	409.2	--	8.1	0.1	--	--	1,015.4
Year ended December 31, 2007	301.5	281.9	0.1	1.2	0.5	--	--	585.2
Intersegment and intrasegment revenues:								
Year ended December 31, 2009	6,865.5	515.3	47.6	1.3	612.3	--	(8,042.0)	--
Year ended December 31, 2008	8,091.7	881.6	75.1	1.4	663.3	--	(9,713.1)	--
Year ended December 31, 2007	5,436.3	205.5	48.6	2.0	522.6	--	(6,215.0)	--
Total revenues:								
Year ended December 31, 2009	19,174.5	3,665.2	7,238.6	341.2	3,133.4	--	(8,042.0)	25,510.9
Year ended December 31, 2008	23,405.5	4,698.0	12,838.9	269.8	3,970.5	--	(9,713.1)	35,469.6
Year ended December 31, 2007	17,887.0	2,531.4	9,152.4	225.8	3,132.2	--	(6,215.0)	26,713.8
Equity in income of unconsolidated affiliates:								
Year ended December 31, 2009	11.3	4.9	9.3	36.9	(11.2)	41.1	--	92.3
Year ended December 31, 2008	1.4	1.6	11.7	33.7	(13.5)	31.3	--	66.2
Year ended December 31, 2007	7.1	0.2	2.6	12.6	(12.0)	3.1	--	13.6
Gross operating margin:								
Year ended December 31, 2009	1,628.7	501.5	164.4	180.5	364.7	41.1	--	2,880.9
Year ended December 31, 2008	1,325.0	589.9	132.2	187.0	374.9	31.3	--	2,640.3
Year ended December 31, 2007	848.0	493.2	109.6	171.6	342.0	3.1	--	1,967.5
Segment assets:								
At December 31, 2009	7,191.2	6,918.7	865.3	2,121.4	3,359.0	1,525.6	1,207.3	23,188.5
At December 31, 2008	6,459.3	6,118.8	883.0	2,061.8	3,308.9	1,598.8	2,015.4	22,446.0
At December 31, 2007	5,488.5	5,502.3	858.8	2,152.3	2,631.9	1,653.4	1,588.3	19,875.5
Property, plant and equipment, net (see Note 8):								
At December 31, 2009	6,392.8	6,074.6	377.3	1,480.9	2,156.3	--	1,207.3	17,689.2
At December 31, 2008	5,622.4	5,223.6	386.9	1,394.5	2,090.0	--	2,015.4	16,732.8
At December 31, 2007	4,770.4	4,577.4	363.7	1,452.6	1,556.7	--	1,588.3	14,309.1
Investments in unconsolidated affiliates (see Note 9):								
At December 31, 2009	141.6	32.0	178.5	456.9	81.6	1,525.6	--	2,416.2
At December 31, 2008	144.3	25.9	186.2	469.0	86.5	1,598.8	--	2,510.7
At December 31, 2007	117.0	3.5	184.8	484.6	95.7	1,653.4	--	2,539.0
Intangible assets, net (see Note 11):								
At December 31, 2009	315.6	527.2	6.5	101.5	114.0	--	--	1,064.8
At December 31, 2008	351.4	584.4	6.9	116.2	124.0	--	--	1,182.9
At December 31, 2007	375.1	636.5	7.3	133.0	62.2	--	--	1,214.1
Goodwill (see Note 11):								
At December 31, 2009	341.2	284.9	303.0	82.1	1,007.1	--	--	2,018.3
At December 31, 2008	341.2	284.9	303.0	82.1	1,008.4	--	--	2,019.6
At December 31, 2007	226.0	284.9	303.0	82.1	917.3	--	--	1,813.3

Our consolidated revenues are derived from a wide customer base. During 2009, our largest non-affiliated customer based on revenues was Shell Oil Company and its affiliates, which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero Energy Corporation and its affiliates, which accounted for 11.2% and 8.9%, respectively, of our revenues.

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and expenses for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services:			
Sales of NGLs	$ 11,598.9	$ 14,573.5	$ 11,701.3
Sales of other petroleum and related products	1.8	2.4	3.0
Midstream services	708.3	737.9	746.4
Total	12,309.0	15,313.8	12,450.7
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,410.5	3,083.1	1,676.7
Midstream services	739.4	733.3	649.2
Total	3,149.9	3,816.4	2,325.9
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	7,110.6	12,696.2	9,048.5
Midstream services	80.4	67.6	55.3
Total	7,191.0	12,763.8	9,103.8
Offshore Pipelines & Services:			
Sales of natural gas	1.2	2.8	3.2
Sales of crude oil	5.3	11.1	12.1
Midstream services	333.4	254.5	208.5
Total	339.9	268.4	223.8
Petrochemical & Refined Products Services:			
Sales of other petroleum and related products	1,991.8	2,757.6	2,207.2
Midstream services	529.3	549.6	402.4
Total	2,521.1	3,307.2	2,609.6
Total consolidated revenues	$ 25,510.9	$ 35,469.6	$ 26,713.8
Consolidated costs and expenses			
Operating costs and expenses:			
Cost of sales for our marketing activities	$ 18,656.7	$ 28,250.2	$ 21,142.5
Depreciation, amortization and accretion	809.3	725.4	647.9
Gain on sale of assets and related transactions	--	(4.0)	(7.8)
Non-cash impairment charges	33.5	--	--
Other operating costs and expenses	4,066.3	4,647.3	3,619.5
General and administrative costs	182.8	144.8	131.9
Total consolidated costs and expenses	$ 23,748.6	$ 33,763.7	$ 25,534.0

Note 15. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Revenues – related parties:			
EPCO and affiliates	$ --	$ --	$ 0.2
Energy Transfer Equity and subsidiaries	423.1	618.5	294.5
Unconsolidated affiliates	175.9	396.9	290.5
Total revenue – related parties	$ 599.0	$ 1,015.4	$ 585.2
Costs and expenses – related parties:			
EPCO and affiliates	$ 592.5	$ 555.4	$ 470.7
Energy Transfer Equity and subsidiaries	443.8	192.2	35.2
Cenac and affiliates	40.9	48.3	--
Unconsolidated affiliates	38.2	56.1	41.0
Total costs and expenses – related parties	$ 1,115.4	$ 852.0	$ 546.9
Other expense – related parties:			
EPCO and affiliates	$ 4.1	$ 0.3	$ 0.2

The following table summarizes our related party receivable and payable amounts at the dates indicated:

	December 31,	
	2009	2008
Accounts receivable - related parties:		
EPCO and affiliates	$ --	$ 0.2
Energy Transfer Equity and subsidiaries	28.2	35.0
Other	10.2	--
Total accounts receivable – related parties	$ 38.4	$ 35.2
Accounts payable - related parties:		
EPCO and affiliates	$ 27.8	$ 14.1
Energy Transfer Equity and subsidiaries	33.4	0.1
Other	9.6	3.4
Total accounts payable – related parties	$ 70.8	$ 17.6

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.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

§ EPCO and its privately held affiliates;

§ EPE Holdings, our sole general partner; and

§ the Employee Partnerships (see Note 5).

EPCO is a privately held company controlled by Dan L. Duncan, who is also a Director and Chairman of EPE Holdings and EPGP. At December 31, 2009, EPCO and its affiliates beneficially owned interests in the following entities:

	Number of Units	Percentage of Outstanding Units
Enterprise Products Partners (1) (2)	191,363,613	31.3%
Parent Company (3)	108,503,133	78.0%

(1) Includes 4,520,431 Class B units and 21,167,783 common units owned by the Parent Company.
(2) The Parent Company owns 100% of Enterprise Products Partners' general partner, EPGP.
(3) An affiliate of EPCO owns 100% of our general partner.

The principal business activity of EPE Holdings and EPGP is to act as the sole managing partner of the Parent Company and Enterprise Products Partners, respectively. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

The Parent Company, EPE Holdings, Enterprise Products Partners and EPGP are separate legal entities apart from each other and apart from EPCO and their respective other affiliates, with assets and liabilities that are separate from those of EPCO and their respective other affiliates. EPCO and its privately held subsidiaries depend on the cash distributions they receive from the Parent Company, Enterprise Products Partners and other investments to fund their other operations and to meet their debt obligations. The following table presents cash distributions received by EPCO and its privately held affiliates from the Parent Company and Enterprise Products Partners for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Enterprise Products Partners	$ 314.5	$ 281.1	$ 263.4
Parent Company	205.2	158.7	125.5
Total distributions	$ 519.7	$ 439.8	$ 388.9

Substantially all of the ownership interests in Enterprise Products Partners that are owned or controlled by the Parent Company are pledged as security under its credit facility. In addition, substantially all of the ownership interests in the Parent Company and Enterprise Products Partners that are owned or controlled by EPCO and its affiliates, other than those interests owned by the Parent Company, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a privately held affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including the Parent Company and Enterprise Products Partners.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO ASA

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. The Parent Company, Enterprise Products Partners, Duncan Energy Partners and their respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, 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 incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

§ EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to Enterprise Products Partners (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to Enterprise Products Partners its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. Enterprise Products Partners records the full value of these payments made by EPCO on its behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to its partnership.

Our operating costs and expenses include amounts paid 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 include amounts paid to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Operating costs and expenses	$ 495.3	$ 463.2	$ 387.7
General and administrative expenses	97.2	92.2	83.0
Total costs and expenses	$ 592.5	$ 555.4	$ 470.7

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 ASA also addresses potential conflicts that may arise among the Parent Company (including EPE Holdings), Enterprise Products Partners (including EPGP), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities (as defined within the ASA) with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes the Parent Company, Enterprise Products Partners, Duncan Energy Partners and their respective general partners.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by the Parent Company and Enterprise Products Partners to EPCO of distributions of cash or securities, if any, made by EPCO Unit to its Class B limited partners. The ASA amendment also extended the term under which EPCO provides services to the partnership entities from December 2010 to December 2013 and made other updating and conforming changes.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here.

The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- § We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $155.5 million, $362.9 million and $268.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

- § We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $11.0 million, $24.5 million and $17.3 million for the years ended December 31, 2009, 2008 and 2007, respectively. Expenses with Promix were $26.0 million, $38.7 million and $30.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

- § For the years ended December 31, 2008 and 2007, we paid $1.7 million and $3.8 million, respectively, to Centennial in connection with a pipeline capacity lease. In addition, we paid $6.7 million, $6.6 million and $5.3 million to Centennial for the years ended December 31, 2009, 2008 and 2007 for other pipeline transportation services, respectively.

- § For the years ended December 31, 2009, 2008 and 2007, we paid Seaway $3.4 million, $6.0 million and $4.7 million, respectively, for transportation and tank rentals in connection with our crude oil marketing activities.

- § We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $10.7 million, $11.2 million and $11.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

- § Enterprise Products Partners has a long-term sales contract with a subsidiary of ETP. In addition, Enterprise Products Partners and another subsidiary of ETP transport natural gas on each other's systems and share operating expenses on certain pipelines. A subsidiary of ETP also sells natural gas to Enterprise Products Partners. See previous table for related party revenue and expense amounts recorded by Enterprise Products Partners in connection with Energy Transfer Equity.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in five midstream energy businesses from EPO in a drop down transaction. On December 8, 2008, through a second drop down transaction, Duncan Energy Partners acquired controlling interests in three additional midstream energy businesses from EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in (i) the gathering, transportation and storage of natural gas; (ii) NGL transportation and fractionation; (iii) the storage of NGL and petrochemical products; (iv) the transportation of petrochemical products and (v) the marketing of NGLs and natural gas.

At December 31, 2009, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At December 31, 2009, EPO owned 58.6% of Duncan Energy Partners' limited partner interests and 100% of its general partner. Due to Enterprise Products Partners' control of Duncan Energy Partners, its financial statements are consolidated with those of Enterprise Products Partners and Enterprise Products Partners' transactions with Duncan Energy Partners are eliminated in consolidation.

Relationship with Cenac

In connection with our marine services acquisition in February 2008, Cenac and affiliates became a related party of ours. We entered into a transitional operating agreement with Cenac in which our fleet of tow boats and tank barges (which were primarily acquired from Cenac) continued to be operated by employees of Cenac for a period of up to two years following the acquisition. Under this agreement, we paid Cenac a monthly operating fee and reimbursed Cenac for personnel salaries and related employee benefit expenses, certain repairs and maintenance expenses and insurance premiums on the equipment. Effective August 1, 2009, the transitional operating agreement was terminated. Personnel providing services pursuant to the agreement became employees of EPCO and will continue to provide services under the ASA. Concurrently with the termination of the transitional operating agreement, we entered into a two-year consulting agreement with Mr. Cenac and Cenac Marine Services, L.L.C. under which Mr. Cenac has agreed to supervise the day-to-day operations of our marine services business and, at our request, provide related management and transitional services.

Note 16. Provision for Income Taxes

Our provision for income taxes relates primarily to federal and state income taxes of Seminole and Dixie, our two largest corporations subject to such income taxes. In addition, with the amendment of the Texas Margin Tax, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	For Year Ended December 31,		
	2009	2008	2007
Current:			
Federal	$ 7.9	$ 4.9	$ 4.7
State	11.9	23.9	5.1
Foreign	1.0	0.4	0.1
Total current	20.8	29.2	9.9
Deferred:			
Federal	4.8	0.8	2.8
State	(0.3)	1.0	3.1
Total deferred	4.5	1.8	5.9
Total provision for income taxes	$ 25.3	$ 31.0	$ 15.8

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For Year Ended December 31,		
	2009	2008	2007
Pre Tax Net Book Income (“NBI”)	$ 1,165.6	$ 1,176.1	$ 777.8
Texas Margin Tax	$ 10.1	$ 23.9	$ 7.7
State income taxes (net of federal benefit)	1.3	0.5	0.3
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	8.3	6.3	5.3
Valuation allowance	(1.7)	(1.4)	2.4
Expiration of tax net operating loss	1.7	--	--
Other permanent differences	5.6	1.7	0.1
Provision for income taxes	$ 25.3	$ 31.0	$ 15.8
Effective income tax rate	2.2%	2.6%	2.0%

Significant components of deferred tax assets and deferred tax liabilities as of December 31, 2009 and 2008 are as follows:

	At December 31, 2009	At December 31, 2008
Deferred tax assets:		
Net operating loss carryovers (1)	$ 24.6	$ 26.3
Property, plant and equipment	--	0.8
Employee benefit plans	2.8	2.6
Deferred revenue	1.1	1.0
Reserve for legal fees and damages	--	0.3
Equity investment in partnerships	1.0	0.6
AROs	0.1	0.1
Accruals	1.3	0.9
Total deferred tax assets	30.9	32.6
Valuation allowance (2)	2.2	3.9
Net deferred tax assets	28.7	28.7
Deferred tax liabilities:		
Property, plant and equipment	97.4	92.9
Other	--	0.1
Total deferred tax liabilities	97.4	93.0
Total net deferred tax liabilities	$ (68.7)	$ (64.3)
Current portion of total net deferred tax assets	$ 1.9	$ 1.4
Long-term portion of total net deferred tax liabilities	$ (70.6)	$ (65.7)

(1) These losses expire in various years between 2010 and 2028 and are subject to limitations on their utilization.
(2) We record a valuation allowance to reduce our deferred tax assets to the amount of future benefit that is more likely than not to be realized.

On May 18, 2006, the State of Texas enacted House Bill 3 which revised the pre-existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax (i.e., the Texas Margin Tax), including previously non-taxable entities such as limited liability companies, limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the Texas Margin Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Due to the enactment of the Texas Margin Tax, we recorded a net deferred tax asset of $0.3 million and a liability of $1.0 million during the years ended December 31, 2009 and 2008, respectively. The offsetting net benefit of $0.3 million and net charge of $1.0 million is shown on our Statements of Consolidated Operations for the years ended December 31, 2009 and 2008, respectively, as a component of “Provision for income taxes.”

Note 17. Earnings Per Unit

Basic and diluted earnings per unit is computed by dividing net income or loss allocated to limited partners by the weighted-average number of Units outstanding during a period, including Class B Units (see below). The amount of net income allocated to limited partners is derived by subtracting, from net income or loss, our general partner’s share of such net income or loss.

As consideration for the contribution of 4,400,000 common units of TEPPCO and the 100% membership interest in TEPPCO GP (including associated TEPPCO IDRs) in May 2007, the Parent Company issued 14,173,304 Class B Units and 16,000,000 Class C Units to private company affiliates of EPCO that are under common control with the Parent Company. As a result of this common control relationship, the Class B Units, which were distribution bearing, were treated as outstanding securities for purposes of calculating our basic and diluted earnings per Unit. On July 12, 2007, all of the outstanding 14,173,304 Class B Units were converted to Units on a one-to-one basis. On February 1, 2009, all of the outstanding 16,000,000 Class C Units were converted to Units on a one-to-one basis. The Class C Units were non-participating in current or undistributed earnings prior to conversion. The Units into which the Class C Units were converted were eligible to receive cash distributions beginning with the distribution paid in May 2009. See Note 13 for additional information regarding the Class B and C Units.

The following table shows the allocation of net income to our general partner for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Net income	$ 204.1	$ 164.0	$ 109.0
Multiplied by general partner ownership interest	0.01%	0.01%	0.01%
General partner interest in net income	$ *	$ *	$ *

The following table shows the calculation of our limited partners' interest in net income and basic and diluted earnings per Unit.

	For Year Ended December 31,		
	2009	2008	2007
BASIC AND DILUTED EARNINGS PER UNIT			
Numerator:			
Net income before general partner interest	$ 204.1	$ 164.0	$ 109.0
General partner interest in net income	*	*	*
Limited partners' interest in net income	$ 204.1	$ 164.0	$ 109.0
Denominator:			
Units	137.8	123.2	104.9
Class B Units	--	--	7.5
Total	137.8	123.2	112.4
Basic and diluted earnings per Unit:			
Net income before general partner interest	$ 1.48	$ 1.33	$ 0.97
General partner interest in net income	*	*	*
Limited partners' interest in net income	$ 1.48	$ 1.33	$ 0.97

* Amount is negligible

Note 18. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as defendants in litigation and legal proceedings relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

We evaluate our ongoing litigation based upon a combination of litigation and settlement alternatives. These reviews are updated as the facts and combinations of the cases develop or change. Assessing and predicting the outcome of these matters involves substantial uncertainties. In the event that the assumptions we used to evaluate these matters change in future periods or new information becomes available, we may be required to record a liability for an adverse outcome. In an effort to mitigate potential adverse consequences of litigation, we could also seek to settle legal proceedings brought against us. We have not recorded any significant reserves for any litigation in our financial statements.

Parent Company Matters. In February 2008, Joel A. Gerber, a purported unitholder of the Parent Company, filed a derivative complaint on behalf of the Parent Company in the Court of Chancery of the State of Delaware. The complaint names as defendants EPE Holdings, the Board of Directors of EPE Holdings, EPCO, and Dan L. Duncan and certain of his affiliates. The Parent Company is named as a nominal defendant. The complaint alleges that the defendants, in breach of their fiduciary duties to the Parent Company and its unitholders, caused the Parent Company to purchase in May 2007 the TEPPCO GP membership interests and TEPPCO units from Mr. Duncan's affiliates at an unfair price. The complaint also alleges that Charles E. McMahen, Edwin E. Smith and Thurmon Andress, constituting the three members of EPE Holdings' ACG Committee, cannot be considered independent because of their relationships with Mr. Duncan. The complaint seeks relief (i) awarding damages for profits allegedly obtained by the defendants as a result of the alleged wrongdoings in the complaint and (ii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. Management believes this lawsuit is without merit and intends to vigorously defend against it. See Note 15 for information regarding our relationship with Mr. Duncan and his affiliates.

Enterprise Products Partners' Matters. On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of the State of Delaware (the "Delaware Court"), in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and Enterprise Product Partners or their affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, certain of its current and former directors, and certain of its affiliates, (ii) Enterprise Products Partners and certain of its affiliates, (iii) EPCO and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into specified transactions that were unfair to TEPPCO or otherwise unfairly favored Enterprise Products Partners or its affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and Enterprise Products Partners in August 2006 (the plaintiff alleges that TEPPCO did not receive fair value for allowing Enterprise Products Partners to participate in the joint venture); (ii) the sale by TEPPCO of its Pioneer natural gas processing plant and certain gas processing rights to Enterprise Products Partners in March 2006 (the plaintiff alleges that the purchase price paid by Enterprise Products Partners did not provide fair value to TEPPCO) and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's incentive distribution rights in exchange for TEPPCO units. The amended complaint seeks (i) rescission of the amendments to TEPPCO's partnership agreement, (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint and (iii) an award to plaintiff of the costs of the action, including fees and expenses of his attorneys and experts. By its Opinion and Order dated November 25, 2008, the Delaware Court dismissed Mr. Brinckerhoff's individual and putative class action claims with respect to the amendments to TEPPCO's partnership agreement. We refer to this action and the remaining claims in this action as the "Derivative Action."

On April 29, 2009, Peter Brinckerhoff and Renee Horowitz, as Attorney in Fact for Rae Kenrow, purported unitholders of TEPPCO, filed separate complaints in the Delaware Court as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger. On May 11, 2009, these actions were consolidated under the caption Texas Eastern Products Pipeline Company, LLC Merger Litigation, C.A. No. 4548-VCL ("Merger Action"). The complaints name as defendants Enterprise Products Partners, EPGP, TEPPCO GP, the directors of TEPPCO GP, EPCO and Dan L. Duncan.

The Merger Action complaints allege, among other things, that the terms of the merger (as proposed as of the time the Merger Action complaints were filed) are grossly unfair to TEPPCO's unitholders and that the TEPPCO Merger is an attempt to extinguish the Derivative Action without consideration. The complaints further allege that the process through which the Special Committee of the

ACG Committee of TEPPCO GP was appointed to consider the TEPPCO Merger is contrary to the spirit and intent of TEPPCO's partnership agreement and constitutes a breach of the implied covenant of fair dealing.

The complaints seek relief (i) enjoining the defendants and all persons acting in concert with them from pursuing the TEPPCO Merger, (ii) rescinding the TEPPCO Merger to the extent it is consummated, or awarding rescissory damages in respect thereof, (iii) directing the defendants to account for all damages suffered or to be suffered by the plaintiffs and the purported class as a result of the defendants' alleged wrongful conduct, and (iv) awarding plaintiffs' costs of the actions, including fees and expenses of their attorneys and experts.

On August 5, 2009, the parties entered into a Stipulation and Agreement of Compromise, Settlement and Release (the "Settlement Agreement"). Pursuant to the Settlement Agreement, the board of directors of TEPPCO GP recommended to TEPPCO's unitholders that they approve the adoption of the merger agreement and took all necessary steps to seek unitholder approval for the merger.

The Delaware Court approved the Settlement Agreement on January 15, 2010, dismissing with prejudice the Merger Action and the Derivative Action.

Additionally, on June 29 and 30, 2009, respectively, M. Lee Arnold and Sharon Olesky, purported unitholders of TEPPCO, filed separate complaints in the District Courts of Harris County, Texas, as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger (the "Texas Actions"). The complaints name as defendants Enterprise Products Partners, TEPPCO, TEPPCO GP, EPGP, EPCO, Dan L. Duncan, Jerry Thompson, and the board of directors of TEPPCO GP. The allegations in the complaints are similar to the complaints filed in Delaware on April 29, 2009 and seek similar relief. The named plaintiffs in the two Texas Actions (the "Texas Plaintiffs/Objectors") also appeared in the Delaware proceedings as objectors to the settlement of those cases which were then awaiting court approval. On October 7, 2009, the Texas Plaintiffs/Objectors and the parties to the Settlement Agreement entered into a Stipulation to Withdraw Objection (the "Stipulation"). In accordance with the Stipulation, and upon the receipt of Final Court Approval (as defined in the Settlement Agreement), the Texas Plaintiffs/Objectors agreed to dismiss the Texas Actions with prejudice. As of March 1, 2010, the Texas Actions have been dismissed with prejudice pursuant to the Settlement Agreement.

In February 2007, EPO received a letter from the Environment and Natural Resources Division of the U.S. Department of Justice related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third-party, Magellan Ammonia Pipeline, L.P. ("Magellan"), and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. This matter was settled in September 2009, and Magellan has agreed to pay all assessed penalties.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment ("CDPHE") filed suit against Enterprise Products Partners and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline's storm water permit and appropriate storm water plan. Enterprise Products Partners has entered into a settlement agreement with the State that dismisses the suit and assesses a fine of approximately $0.2 million.

The CDPHE, through its Air Pollution Control Division, has proposed a Compliance Order on Consent with Enterprise Gas Processing, L.L.C for alleged violations of the Colorado Air Pollution and Prevention and Control Act ("Colorado Act") with respect to operations of the Meeker Gas Processing Plant. The Compliance Order proposes an administrative fine of approximately $0.3 million and would require the Meeker Gas Processing Plant to be operated in compliance with the Colorado Act. We have entered into discussions regarding the terms of the Compliance Order.

ENTERPRISE GP HOLDINGS L.P.
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In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. ("Marathon") as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws. Marathon agreed to a Consent Decree with the State which was approved by the District Court on December 21, 2009. Under the Decree, Marathon paid the State approximately $0.6 million, agreed to $4.5 million of additional environmental projects in New Mexico and agreed to two projects for "corrective measures" at the facility. We are in discussions with Marathon regarding the responsibility for these payments. We believe that any potential payment we make will not have a material impact on our consolidated financial position, results of operations or cash flows.

In connection with our dissociation from TOPS (see Note 8), Oiltanking filed an original petition against Enterprise Offshore Port System, LLC, EPO, TEPPCO O/S Port System, LLC, TEPPCO and TEPPCO GP in the District Court of Harris County, Texas, 61st Judicial District (Cause No. 2009-31367), asserting, among other things, that the dissociation was wrongful and in breach of the TOPS partnership agreement, citing provisions of the agreement that, if applicable, would continue to obligate us and TEPPCO to make capital contributions to fund the project and impose liabilities on us and TEPPCO. On September 17, 2009, Enterprise Products Partners and TEPPCO entered into a settlement agreement with certain affiliates of Oiltanking and TOPS that resolved all disputes between the parties related to the business and affairs of the TOPS project (including the litigation described above). We recognized approximately $66.9 million of expense during 2009 in connection with this settlement. This charge is classified within our Offshore Pipelines & Services business segment.

Energy Transfer Equity Matters. In July 2007, ETP announced that it was under investigation by the FERC with respect to (i) whether ETP engaged in manipulation or improper trading activities in the Houston Ship Channel market around the time of the hurricanes in the fall of 2005 and other prior periods in order to benefit financially from commodity derivative instrument positions and from certain index-priced physical gas purchases in the Houston Ship Channel market and (ii) whether ETP manipulated daily prices at the Waha and Permian hubs in west Texas on two dates. Certain third-party lawsuits were also filed in connection with these matters.

In September 2009, ETP announced that the FERC approved a settlement agreement related to these allegations. The settlement agreement provides that ETP make a $5.0 million payment to the federal government and the FERC will dismiss all claims against ETP. Separate from the payment to the federal government, ETP also is required to establish a $25.0 million fund for the purpose of settling related third-party claims against ETP. This fund amount will be paid into a specific account held by a financial institution selected by mutual agreement of ETP and the FERC. An administrative law judge appointed by the FERC will determine the validity of any third-party claim against this fund. Any party who receives money from this fund will be required to waive all claims against ETP related to this matter. Management of ETP believes that the application of this fund will resolve the existing litigation related to this matter, although, in the event that all plaintiffs in the existing litigation do not participate in this fund, these non-participating plaintiffs will be entitled to continue their litigation claims through the judiciary system.

Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that ETP does not admit or concede to the FERC or any third-party any actual or potential fault, wrongdoing or liability in connection with its alleged conduct related to the FERC claims.

The FERC's actions against ETP also included allegations related to its Oasis pipeline, which is an intrastate pipeline that transports natural gas between the Waha and Katy hubs in Texas. The allegations related to the Oasis pipeline included claims that the pipeline violated Natural Gas Policy Act regulations from January 2004 through June 2006 by granting undue preference to ETP's affiliates. In March 2009, ETP entered into a separate settlement agreement with the FERC related to these allegations. The Oasis settlement agreement did not require ETP to make any payments to the federal government or any other parties.

Regulatory Matters

Certain 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. On June 26, 2009, the U.S. House of Representatives passed the “American Clean Energy and Security Act of 2009,” or “ACESA,” which would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain greenhouse gas emission “allowances” corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun work on its own legislation for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency (“EPA”) announced its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of greenhouse gases, any such regulation could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases would likely require us to incur increased operating costs, and may have an adverse effect on our business, financial position, demand for our operations, results of operations and cash flows.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2009. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**
Scheduled maturities of long-term debt	$ 12,378.5	$ 562.5	$ 915.8	$ 1,452.5	$ 1,208.5	$ 1,949.0	$ 6,290.2
Estimated cash interest payments	$ 12,520.3	$ 706.4	$ 653.7	$ 599.4	$ 527.1	$ 458.5	$ 9,575.2
Operating lease obligations	$ 343.9	$ 37.6	$ 35.3	$ 32.7	$ 27.3	$ 21.5	$ 189.5
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 5,697.6	$ 1,308.9	$ 685.5	$ 696.3	$ 487.5	$ 471.8	$ 2,047.6
NGLs	$ 2,943.0	$ 997.0	$ 339.3	$ 329.8	$ 329.7	$ 329.7	$ 617.5
Crude oil	$ 237.3	$ 237.3	$ --	$ --	$ --	$ --	$ --
Petrochemicals & refined products	$ 2,642.2	$ 1,486.6	$ 586.0	$ 238.5	$ 113.9	$ 72.4	$ 144.8
Other	$ 114.1	$ 21.2	$ 12.2	$ 11.9	$ 11.8	$ 11.0	$ 46.0
Underlying major volume commitments:							
Natural gas (in BBtus) (1)	969,180	221,530	114,304	116,146	83,854	81,154	352,192
NGLs (in MBbls) (2)	49,300	19,048	5,337	5,159	5,158	5,158	9,440
Crude oil (in MBbls) (2)	2,985	2,985	--	--	--	--	--
Petrochemicals & refined products (in MBbls)	35,034	19,523	7,856	3,266	1,509	960	1,920
Service payment commitments	$ 575.6	$ 72.0	$ 57.0	$ 56.7	$ 55.1	$ 55.0	$ 279.8
Capital expenditure commitments	$ 497.5	$ 497.5	$ --	$ --	$ --	$ --	$ --

(1) Volume is measured in billion British thermal units (“BBtus”).
(2) Volume is measured in thousands of barrels (“MBbls”).

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 12 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with affiliates of EPCO and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have current terms that range from 14 to 20 years. The agreements for leased office space with affiliates of EPCO and underground NGL storage caverns we lease from a third party include renewal options that could extend these contracts for up to an additional 20 years. The remainder of our material lease agreements do not provide for additional renewal terms.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2009, 2008 or 2007.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with retained leases contributed to us by EPCO in 1998. EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2009, the retained leases were for approximately 100 railcars. EPCO's minimum future rental payments under these leases are $0.7 million for each of the years 2010 through 2015 and $0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Lease and rental expense included in costs and expenses was $60.7 million, $56.8 million and $61.4 million during the years ended December 31, 2009, 2008 and 2007, respectively.

Purchase Obligations. We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

§ We have long and short-term product purchase obligations for natural gas, NGLs, crude oil, refined products and certain petrochemicals with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery. At December 31, 2009, we do not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

§ We have long and short-term commitments to pay third-party providers for services. Our contractual service payment commitments primarily represent our obligations under firm pipeline transportation contracts on pipelines owned by third parties. Payment obligations vary by contract, but generally represent a price per unit of volume multiplied by a firm transportation volume commitment. The preceding table shows our estimated future payment obligations under these service contracts.

- § We have short-term payment obligations relating to our capital projects and those of our unconsolidated affiliates. These commitments represent unconditional payment obligations to vendors for services rendered or products purchased. The preceding table presents our share of such commitments for the periods indicated.

Commitments Under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us. See Note 5 for additional information regarding our accounting for equity awards.

Other Claims

As part of our normal business activities with joint venture partners, customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements. As of December 31, 2009, claims against us totaled approximately $21.1 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Other Commitments

We transport and store natural gas, NGLs and petrochemicals for third parties under various processing, storage, transportation and similar agreements. These volumes are either accrued as product payables, in transit for delivery to our customers or held at our storage facilities for redelivery to customers. Under terms of our storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2009, NGL and petrochemical products aggregating 29.8 million barrels were due to be redelivered to their owners along with 17,112 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial. We have guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of $60.0 million in the event of a default by Centennial. At December 31, 2009, we had a liability of $8.4 million representing the estimated fair value of our share of the Centennial debt guaranty. See Note 12 for information regarding Centennial's debt obligations.

In lieu of Centennial procuring insurance to satisfy third-party liabilities arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million (in proportion to our ownership interest in Centennial) in the event of a catastrophic event. At December 31, 2009, we had a liability of $3.6 million representing the estimated fair value of our cash call guaranty. Cash contributions to Centennial under the limited cash call agreement may be covered by our insurance depending on the nature of the catastrophic event.

Note 19. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, refined products and certain petrochemicals. We also market natural gas, NGLs, crude oil and other hydrocarbon products. As such, our financial position, results of operations and cash flows may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products (e.g., natural gas processing margins are influenced by the ratio of natural gas prices to crude oil prices). The prices of hydrocarbon products are subject to fluctuation in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of hydrocarbon products gathered, transported, processed, fractionated or stored at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, for reasons such as depressed commodity prices or a decrease in exploration and development activities, could result in a decline in the volume of natural gas, NGLs, refined products and crude oil handled by our facilities.

A reduction in demand for natural gas, crude oil, NGL and other hydrocarbon products by the petrochemical, refining or heating industries, whether because of: (i) general economic conditions, (ii) reduced demand by consumers for the end products made using such products, (iii) increased competition from other products due to pricing differences, (iv) adverse weather conditions, (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could adversely affect our financial position, results of operations and cash flows.

Credit Risk Due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults. See Note 14 for information regarding our largest customers.

Counterparty Risk with Respect to Derivative Instruments

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral nor do we anticipate nonperformance by our counterparties.

Insurance-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

EPCO's deductible for onshore physical damage from windstorms is currently $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events. With respect to offshore assets, the windstorm deductible is $75.0 million per storm. EPCO's offshore program currently provides $100.0 million in the aggregate. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage is $5.0 million per occurrence. For certain of our major offshore assets, our producer customers have agreed to provide a specified level of physical damage insurance for named windstorms. For example, the producers associated with our Independence Hub and Marco Polo platforms have agreed to cover windstorm generated physical damage costs up to $250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets, but was eliminated for offshore assets. Onshore assets covered by business interruption insurance must be out-of-service in excess of 60 days before any losses from business interruption will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets.

The following table summarizes proceeds we received from weather-related business interruption and property damage insurance claims during the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Business interruption proceeds:			
Hurricanes Katrina and Rita in 2005	$ --	$ 1.1	$ 33.9
Hurricanes Gustav and Ike in 2008	33.2	--	--
Other	--	--	1.4
Total proceeds	33.2	1.1	35.3
Property damage proceeds:			
Hurricanes Katrina and Rita in 2005	38.6	12.1	103.7
Hurricanes Gustav and Ike in 2008	15.1	--	--
Other	0.7	--	1.5
Total proceeds	54.4	12.1	105.2
Total	$ 87.6	$ 13.2	$ 140.5

At December 31, 2009, we have $37.6 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2010. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur as additional information becomes available.

Note 20. Supplemental Cash Flow Information

The following table provides information regarding: (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for federal and state income taxes for the periods indicated.

	For Year Ended December 31, 2009	2008	2007
Decrease (increase) in:			
Accounts and notes receivable – trade	$ (1,069.1)	$ 1,333.9	$ (1,176.4)
Accounts receivable – related party	7.2	0.2	(0.2)
Inventories	(317.4)	14.9	(34.8)
Prepaid and other current assets	71.1	(26.3)	32.7
Other assets	15.0	(12.0)	(2.2)
Increase (decrease) in:			
Accounts payable – trade	(44.4)	(7.2)	42.6
Accounts payable – related party	44.9	3.4	(4.7)
Accrued product payables	1,553.0	(1,720.4)	1,398.8
Accrued expenses	42.4	4.6	126.5
Accrued interest	28.2	13.9	56.6
Other current liabilities	(97.6)	(26.7)	20.3
Other liabilities	16.8	7.1	(1.6)
Net effect of changes in operating accounts	$ 250.1	$ (414.6)	$ 457.6
Cash payments for interest, net of $53.1, $90.7 and $86.5 capitalized in 2009, 2008 and 2007, respectively	$ 699.9	$ 643.0	$ 340.5
Cash payments for federal and state income taxes	$ 29.5	$ 6.8	$ 5.8

We incurred liabilities for construction in progress that had not been paid at December 31, 2009, 2008 and 2007 of $182.6 million, $108.0 million and $98.0 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. These amounts are included under the caption "Contributions in aid of construction costs" on the Statements of Consolidated Cash Flows.

Note 21. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2009 and 2008:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2009:				
Revenues	$ 4,886.9	$ 5,434.3	$ 6,789.4	$ 8,400.3
Operating income	498.2	377.8	353.4	625.2
Net income	317.7	204.0	174.9	443.7
Net income attributable to Enterprise GP Holdings L.P.	62.9	39.1	25.3	76.8
Net income per Unit:				
Basic and diluted	$ 0.47	$ 0.28	$ 0.18	$ 0.55
For the Year Ended December 31, 2008:				
Revenues	$ 8,506.3	$ 10,538.6	$ 10,499.2	$ 5,925.5
Operating income	479.5	468.7	410.0	413.9
Net income	327.9	316.8	249.6	250.8
Net income attributable to Enterprise GP Holdings L.P.	46.6	49.4	42.0	26.0
Net income per Unit:				
Basic and diluted	$ 0.38	$ 0.40	$ 0.34	$ 0.21

Note 22. Supplemental Parent Company Financial Information

In order to fully understand the financial position and results of operations of the Parent Company, we are providing the condensed standalone financial information of Enterprise GP Holdings L.P. apart from that of our consolidated Partnership financial information.

The Parent Company has no operations apart from its investing activities and indirectly overseeing the management of the entities controlled by it. At December 31, 2009, the Parent Company had investments in Enterprise Products Partners, Energy Transfer Equity and their respective general partners. The Parent Company controls Enterprise Products Partners through its ownership of EPGP. The Parent Company owns noncontrolling partnership and membership interests in Energy Transfer Equity and LE GP, respectively. At December 31, 2008, the Parent Company had investments in Enterprise Products Partners, TEPPCO, Energy Transfer Equity and their respective general partners. On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners.

The Parent Company's primary cash requirements are for general and administrative costs, debt service requirements and distributions to its partners. The principal sources of cash flow for the Parent Company are the distributions it receives from its investments in Enterprise Products Partners, Energy Transfer Equity and their respective general partners. The amount of cash distributions the Parent Company is able to pay its unitholders may fluctuate based on the level of distributions it receives from its investments. For example, if EPO is not able to satisfy certain financial covenants in accordance with its credit agreements, Enterprise Products Partners would be restricted from making quarterly cash distributions to its partners, which includes the Parent Company.

Factors such as capital contributions, debt service requirements, general and administrative costs, reserves for future distributions and other cash reserves established by the Board of EPE Holdings may affect the distributions the Parent Company makes to its unitholders. The Parent Company's credit facility contains covenants requiring it to maintain certain financial ratios. Also, the Parent Company is prohibited from making any distribution to its unitholders if such distribution would cause an event of default or otherwise violate a covenant under its credit facility.

The Parent Company's assets and liabilities are not available to satisfy the debts and other obligations of Enterprise Products Partners, Energy Transfer Equity or their respective general partners. Conversely, the assets and liabilities of these entities are not available to satisfy the debts and obligations of the Parent Company.

Enterprise Products Partners and EPGP

At December 31, 2009, the Parent Company owned 21,167,783 common units of Enterprise Products Partners and 100% of the membership interests of EPGP, which is entitled to 2% of the cash distributions paid by Enterprise Products Partners as well as the IDRs of Enterprise Products Partners.

EPGP's percentage interest in Enterprise Products Partners' quarterly cash distributions is increased through its ownership of the associated IDRs, after certain specified target levels of distribution rates are met by Enterprise Products Partners. EPGP's quarterly general partner and associated incentive distribution thresholds are as follows:

- 2% of quarterly cash distributions up to $0.253 per unit paid by Enterprise Products Partners;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit paid by Enterprise Products Partners; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit paid by Enterprise Products Partners.

The following table summarizes the distributions received by EPGP from Enterprise Products Partners for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
From 2% general partner interest	$ 21.8	$ 18.2	$ 16.9
From IDRs	161.3	125.9	107.4
Total	$ 183.1	$ 144.1	$ 124.3

Energy Transfer Equity and LE GP

On May 7, 2007, the Parent Company acquired 38,976,090 common units of Energy Transfer Equity and approximately 34.9% of the membership interests in LE GP for $1.65 billion in cash. On January 22, 2009, the Parent Company acquired an additional 5.7% membership interest in LE GP for $0.8 million, which increased our total ownership in LE GP to 40.6%.

LE GP owns a 0.31% general partner interest in Energy Transfer Equity, which general partner interest has no associated IDRs in the quarterly cash distributions of Energy Transfer Equity. The business purpose of LE GP is to manage the affairs and operations of Energy Transfer Equity. LE GP has no separate business activities outside of those conducted by Energy Transfer Equity.

Energy Transfer Equity is a publicly traded Delaware limited partnership formed in 2002 that completed its initial public offering in February 2006. Energy Transfer Equity's only cash generating assets are its investments in limited and general partner interests of ETP as follows:

§ Direct ownership of 62,500,797 ETP limited partner units, representing approximately 35% of ETP's total outstanding common units at December 31, 2009.

§ Indirect ownership of the general partner interest of ETP (representing a 1.9% interest as of December 31, 2009) and all associated IDRs held by ETP's general partner, of which Energy Transfer Equity owns 100% of the membership interests. Currently, the quarterly general partner and associated IDR thresholds of ETP's general partner are based on the ETP general partner percentage interest, plus the following with respect to the IDRs:

§ 13% of quarterly cash distributions from $0.275 per unit up to $0.3175 per unit paid by ETP;

§ 23% of quarterly cash distributions from $0.3175 per unit up to $0.4125 per unit paid by ETP; and

§ 48% of quarterly cash distributions that exceed $0.4125 per unit paid by ETP.

The following table summarizes the cash distributions received by Energy Transfer Equity from ETP for the periods indicated:

	For Year Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007 (1)	2007 (1)
Limited partners interests	$ 223.4	$ 221.9	$ 70.3	$ 199.2
General partner interest	19.5	17.3	5.1	13.7
IDRs	350.5	298.6	85.8	222.4
Total distributions received	$ 593.4	$ 537.8	$ 161.2	$ 435.3

(1) In November 2007, Energy Transfer Equity changed its fiscal year end from August 31 to December 31. Energy Transfer Equity did not recast its consolidated financial data for prior fiscal periods; however, it did complete a four month transition period that began on September 1, 2007 and ended December 31, 2007.

TEPPCO and TEPPCO GP

Private company affiliates of EPCO contributed equity interests in TEPPCO and TEPPCO GP to the Parent Company in May 2007. As a result of such contributions, the Parent Company owned 4,400,000 common units of TEPPCO and 100% of the membership interests of TEPPCO GP, which was entitled to 2% of the cash distributions of TEPPCO as well as the IDRs of TEPPCO. On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners. As a result, the Parent Company's ownership interests in the TEPPCO units were converted to 5,456,000 common units of Enterprise Products Partners. In addition, the Parent Company's membership interests in TEPPCO GP were exchanged for (i) 1,331,681 common units of Enterprise Products Partners and (ii) EPGP (on behalf of the Parent Company as a wholly owned subsidiary of the Parent Company) was credited in its Enterprise Products Partners' capital account an amount to maintain its 2% general partner interest in Enterprise Products Partners. For additional information regarding the TEPPCO Merger, see Note 1 "Basis of Presentation."

Condensed Parent Company Cash Flow Information

The following table presents the Parent Company's cash flow information for the periods indicated:

	For Year Ended December 31,		
	2009	**2008**	**2007**
Operating activities:			
Net income	$ 204.1	$ 164.0	$ 109.0
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Amortization	2.1	1.3	9.7
Equity income	(259.8)	(238.8)	(187.6)
Cash distributions from investees	355.4	313.5	237.6
Net effect of changes in operating accounts	(3.2)	(5.3)	15.9
Net cash flows provided by operating activities	298.6	234.7	184.6
Investing activities:			
Investments (1)	(38.3)	(7.7)	(1,650.8)
Cash used in investing activities	(38.3)	(7.7)	(1,650.8)
Financing activities:			
Borrowings under debt agreements	117.6	67.6	3,787.0
Repayments of debt	(113.1)	(80.6)	(2,852.0)
Debt issuance costs	--	(0.1)	(18.6)
Cash distributions paid by Parent Company	(266.7)	(213.1)	(159.0)
Proceeds from issuance of Parent Company's Units, net	--	--	739.4
Cash distributions paid by former owners of TEPPCO interests	--	--	(29.8)
Contribution from partners	--	--	0.1
Cash provided by (used in) financing activities	(262.2)	(226.2)	1,467.1
Net change in cash and cash equivalents	(1.9)	0.8	0.9
Cash and cash equivalents, January 1	2.5	1.7	0.8
Cash and cash equivalents, December 31	$ 0.6	$ 2.5	$ 1.7

(1) The amount for 2007 includes the $1.65 billion paid to acquire interests in Energy Transfer Equity and LE GP in May 2007.

The following table details the components of cash distributions received from investees and cash distributions paid by the Parent Company for the periods indicated:

	For Year Ended December 31, 2009	2008	2007
Cash distributions from investees: (1)			
Investment in Enterprise Products Partners and EPGP:			
From common units of Enterprise Products Partners	$ 33.5	$ 27.5	$ 25.8
From 2% general partner interest in Enterprise Products Partners	21.8	18.2	16.9
From general partner IDRs in distributions of Enterprise Products Partners	161.3	123.9	104.7
Investment in TEPPCO and TEPPCO GP:			
From 4,400,000 common units of TEPPCO	9.6	12.5	12.1
From 2% general partner interest in TEPPCO	4.7	5.6	5.0
From general partner IDRs in distributions of TEPPCO	41.8	49.3	43.2
Investment in Energy Transfer Equity and LE GP: (2)			
From 38,976,090 common units of Energy Transfer Equity	82.0	76.0	29.7
From member interest in LE GP	0.7	0.5	0.2
Total cash distributions received	$ 355.4	$ 313.5	$ 237.6
Distributions by the Parent Company:			
EPCO and affiliates	$ 205.7	$ 158.9	$ 125.9
Public	61.0	54.2	33.1
General partner interest	*	*	*
Total distributions by the Parent Company	$ 266.7	$ 213.1	$ 159.0
Distributions paid to affiliates of EPCO that were the former owners of the TEPPCO and TEPPCO GP interests contributed to the Parent Company in May 2007 (3)	$ --	$ --	$ 29.8

* Amount is negligible.
(1) Represents cash distributions received during each reporting period.
(2) The Parent Company received its first cash distribution from Energy Transfer Equity and LE GP in July 2007.
(3) Represents cash distributions paid to affiliates of EPCO that were former owners of these partnership and membership interests prior to the contribution of such interests to the Parent Company in May 2007.

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Condensed Parent Company Balance Sheet Information

The following table presents the Parent Company's balance sheet information at the dates indicated:

	December 31, 2009	December 31, 2008
ASSETS		
Current assets	$ 2.7	$ 4.6
Investments:		
Enterprise Products Partners and EPGP	1,522.8	829.2
TEPPCO and TEPPCO GP (1)	--	708.5
Energy Transfer Equity and LE GP	1,525.6	1,564.0
Total investments	3,048.4	3,101.7
Other assets	6.4	8.2
Total assets	$ 3,057.5	$ 3,114.5
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 17.9	$ 23.2
Long-term debt (see Note 12)	1,081.5	1,077.0
Other long-term liabilities	4.5	13.2
Partners' equity	1,953.6	2,001.1
Total liabilities and partners' equity	$ 3,057.5	$ 3,114.5

(1) On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners.

Condensed Parent Company Income Information

The following table presents the Parent Company's income information for the periods indicated:

	For Year Ended December 31, 2009	2008	2007
Equity income:			
Enterprise Products Partners and EPGP	$ 205.2	$ 167.8	$ 128.5
TEPPCO and TEPPCO GP	13.5	39.7	56.0
Energy Transfer Equity and LE GP	41.1	31.3	3.1
Total equity income	259.8	238.8	187.6
General and administrative costs	10.3	7.3	4.3
Operating income	249.5	231.5	183.3
Other income (expense):			
Interest expense	(45.4)	(67.5)	(74.5)
Interest income	--	--	0.2
Total	(45.4)	(67.5)	(74.3)
Net income	$ 204.1	$ 164.0	$ 109.0

Note 23. Subsequent Event

Enterprise Products Partners Issues $343.1 Million of Common Units

In January 2010, Enterprise Products Partners issued 10,925,000 common units (including an over-allotment of 1,425,000 common units) to the public at an offering price of $32.42 per unit. Enterprise Products Partners used the net cash proceeds of $343.1 million to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility, which may be reborrowed to fund capital expenditures and other growth projects, and for general partnership purposes.

EXHIBIT 12.1

ENTERPRISE GP HOLDINGS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Year Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Consolidated income	$ 1,140.3	$ 1,145.1	$ 762.0	$ 772.4	$ 561.1
Add: Provision for taxes	25.3	31.0	15.8	22.0	8.4
Less: Equity in earnings from unconsolidated affiliates	(92.3)	(66.2)	(13.6)	(25.2)	(34.6)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	1,073.3	1,109.9	764.2	769.2	534.9
Add: Fixed charges	760.6	717.9	594.4	421.7	364.0
Amortization of capitalized interest	15.3	13.4	11.6	9.8	2.0
Distributed income of equity investees	169.3	157.2	116.9	76.5	93.1
Subtotal	2,018.5	1,998.4	1,487.1	1,277.2	994.0
Less: Capitalized interest	(53.1)	(90.7)	(86.5)	(66.4)	(28.8)
Net income attributable to noncontrolling interest	(26.4)	(23.0)	(14.8)	(4.0)	(4.5)
Total earnings	$ 1,939.0	$ 1,884.7	$ 1,385.8	$ 1,206.8	$ 960.7
Fixed charges:					
Interest expense	$ 687.3	$ 608.3	$ 487.4	$ 333.7	$ 315.6
Capitalized interest	53.1	90.7	86.5	66.4	28.8
Interest portion of rental expense	20.2	18.9	20.5	21.6	19.6
Total	$ 760.6	$ 717.9	$ 594.4	$ 421.7	$ 364.0
Ratio of earnings to fixed charges	2.6x	2.6x	2.3x	2.9x	2.6x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, “earnings” is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income from continuing operations before adjustment for income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- the noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term “fixed charges” means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of interest within rental expense; and preference dividend requirements of consolidated subsidiaries.

Exhibit 21.1

LIST OF SUBSIDIARIES
Enterprise GP Holdings L.P.
as of February 1, 2010

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Acadian Gas, LLC	Delaware	Enterprise Products Operating LLC – 34% DEP Operating Partnership, L.P. – 66%
Acadian Gas Pipeline System	Delaware	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Adamana Land Company, LLC	Delaware	Enterprise Products Operating LLC – 100%
Arizona Gas Storage, L.L.C.	Delaware	Enterprise Arizona Gas, L.L.C. – 60% Third Party – 40%
Atlantis Offshore, LLC	Delaware	Manta Ray Gathering Company, L.L.C. – 50% Manta Ray Offshore Gathering Company, L.L.C. – 50%
Baton Rouge Fractionators LLC	Delaware	Enterprise Products Operating LLC – 32.25% Third Parties – 67.75%
Baton Rouge Pipeline LLC	Delaware	Baton Rouge Fractionators LLC – 100%
Baton Rouge Propylene Concentrator LLC	Delaware	Enterprise Products Operating LLC – 30% Third Parties – 70%
Belle Rose NGL Pipeline, L.L.C.	Delaware	Enterprise NGL Pipelines, LLC 41.67% Enterprise Products Operating LLC – 58.33%
Belvieu Environmental Fuels GP, LLC	Texas	Enterprise Products Operating LLC – 100%
Belvieu Environmental Fuels LLC	Texas	Enterprise Products Operating LLC – 99% Belvieu Environmental Fuels GP, LLC – 1%
Cajun Pipeline Company, LLC	Texas	Enterprise Products Operating LLC – 100%
Calcasieu Gas Gathering System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Cameron Highway Oil Pipeline Company	Delaware	Cameron Highway Pipeline I, L.P. – 50% Third Party – 50%
Cameron Highway Pipeline GP, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Cameron Highway Pipeline I, L.P.	Delaware	Enterprise GTM Holdings L.P. – 99% Cameron Highway Pipeline GP, L.L.C. – 1%
Canadian Enterprise Gas Products, Ltd.	Alberta, Canada	Enterprise Products Operating LLC – 100%
Centennial Pipeline LLC	Delaware	TE Products Pipeline Company, LLC – 50% Third Party – 50%
Chama Gas Services, LLC	Delaware	Enterprise New Mexico Ventures, LLC – 75% Third Party – 25%
Chaparral Pipeline Company, LLC	Texas	TEPPCO Midstream Companies, LLC – 99.999% TEPPCO NGL Pipelines, LLC – 0.001%
Chunchula Pipeline Company, LLC	Texas	Enterprise Products Operating LLC – 100%
Crystal Holding, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Cypress Gas Marketing, LLC	Delaware	Acadian Gas, LLC – 100%
Cypress Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
Dean Pipeline Company, LLC	Texas	TEPPCO Midstream Companies, LLC – 99.999% TEPPCO NGL Pipelines, LLC – 0.001%
Deep Gulf Development, LLC	Delaware	Enterprise Offshore Development, LLC – 90% Third Party – 10%

Deepwater Gateway, L.L.C.	Delaware	Enterprise Field Services, LLC – 50% Third Party – 50%
DEP Holdings, LLC	Delaware	Enterprise Products Operating LLC – 100%
DEP Offshore Port System, LLC	Texas	DEP Operating Partnership, L.P. – 100%
DEP OLPGP, LLC	Delaware	Duncan Energy Partners L.P. – 100%
DEP Operating Partnership, L.P.	Delaware	Duncan Energy Partners L.P. – 99.999% DEP OLPGP, LLC – 0.001%
Dixie Pipeline Company	Delaware	E-Cypress, LLC – 100%
Duncan Energy Partners L.P.	Delaware	Enterprise GTM Holdings L.P. – 58.16% DEP Holdings LLC – 0.71% DD Securities LLC – 0.18% EPCO Holdings, Inc. – 0.17% Public – 40.78%
E-Cypress, LLC	Delaware	Enterprise Products Operating LLC – 100%
E-Oaktree, LLC	Delaware	E-Cypress, LLC – 100%
Enterprise Alabama Intrastate, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Arizona Gas, LLC	Delaware	Enterprise Field Services, LLC – 100%
Enterprise Big Thicket Pipeline System LLC	Texas	Enterprise GC, L.P. – 100%
Enterprise Energy Finance Corporation	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Field Services, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Fractionation, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise GC, L.P.	Delaware	Enterprise GTM Holdings L.P. –34% Enterprise Holding III, LLC – 66%
Enterprise GTMGP, LLC	Delaware	Enterprise Products GTM, LLC – 100%
Enterprise GTM Hattiesburg Storage, LLC	Delaware	Crystal Holding, L.L.C. – 100%
Enterprise GTM Holdings L.P.	Delaware	Enterprise Products Operating LLC – 99% Enterprise GTMGP, LLC – 1%
Enterprise GTM Offshore Operating Company, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Gas Liquids LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Gas Processing, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Holding III, LLC	Delaware	DEP Operating Partnership, L.P. – 100%
Enterprise Hydrocarbons L.P.	Delaware	Enterprise Products Texas Operating LLC – 99% Enterprise Products Operating LLC – 1%
Enterprise Intrastate L.P.	Delaware	Enterprise GTM Holdings L.P. – 49% Enterprise Holding III, LLC – 51%
Enterprise Lou-Tex NGL Pipeline L.P.	Texas	Enterprise Products Operating LLC – 99% HSC Pipeline Partnership, LLC – 1%
Enterprise Lou-Tex Propylene Pipeline L.P.	Texas	Enterprise Products Operating LLC – 33% Propylene Pipeline Partnership L.P. – 1% DEP Operating Partnership, L.P. – 66%
Enterprise Louisiana Pipeline LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Marine Services LLC	Delaware	TEPPCO Partners, L.P – 100%.
Enterprise New Mexico Ventures, LLC	Delaware	Enterprise Field Services, LLC – 100%
Enterprise NGL Pipelines, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise NGL Private Lines & Storage, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Offshore Development, LLC	Delaware	Moray Pipeline Company, LLC – 100%
Enterprise Offshore Port System, LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Pathfinder, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Products GP, LLC	Delaware	Enterprise GP Holdings L.P. – 100%

Enterprise Products GTM, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Products Marketing Company LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Products OLPGP, Inc.	Delaware	Enterprise Products Partners L.P. – 100%
Enterprise Products Operating LLC	Texas	Enterprise Products Partners L.P. – 99.999% Enterprise Products OLPGP, Inc. – 0.001%
Enterprise Products Partners L.P.	Delaware	Enterprise Products GP, LLC – 2% Public – 68.05% Dan L. Duncan, EPCO, Inc., Dan Duncan LLC and other Affiliates – 26.61% Enterprise GP Holdings L.P. – 3.34%
Enterprise Products Texas Operating LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Products OLPGP, Inc. – 1%
Enterprise Propane Terminals and Storage, LLC	Delaware	Enterprise Terminals & Storage, LLC – 100%
Enterprise South Texas Gathering L.P.	Delaware	Enterprise Products Operating LLC. – 99% Enterprise Products OLPGP, Inc. – 1%
Enterprise Terminalling LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Gas Liquids LLC – 1%
Enterprise Terminals & Storage, LLC	Delaware	Mapletree, LLC – 100%
Enterprise Texas Pipeline LLC	Texas	Enterprise GTM Holdings L.P. – 49% Enterprise Holding III, LLC – 51%
Enterprise White River Hub, LLC	Delaware	Enterprise Products Operating LLC – 100%
Evangeline Gas Corp.	Delaware	Evangeline Gulf Coast Gas, LLC – 45.05% Third Parties – 54.95%
Evangeline Gas Pipeline Company, L.P.	Texas	Evangeline Gulf Coast Gas, LLC – 45% Evangeline Gas Corp. – 10% Third Party – 45%
Evangeline Gulf Coast Gas, LLC	Delaware	Acadian Gas, LLC – 100%
First Reserve Gas, L.L.C.	Delaware	Crystal Holding, L.L.C. – 100%
Flextrend Development Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Groves RGP Pipeline LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Products Texas Operating LLC – 1%
Hattiesburg Gas Storage Company	Delaware	First Reserve Gas, L.L.C. – 50% Hattiesburg Industrial Gas Sales, L.L.C. – 50%
Hattiesburg Industrial Gas Sales, L.L.C.	Delaware	First Reserve Gas, L.L.C. – 100%
High Island Offshore System, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
HSC Pipeline Partnership, LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Products OLPGP, Inc. – 1%
Independence Hub, LLC	Delaware	Enterprise Field Services, LLC – 80% Third Party – 20%
Jonah Gas Gathering Company	Wyoming	TEPPCO Midstream Companies, LLC – 80.64% Enterprise Gas Processing LLC – 19.36%
Jonah Gas Marketing, LLC	Delaware	Jonah Gas Gathering Company – 100%
K/D/S Promix, L.L.C.	Delaware	Enterprise Fractionation, LLC – 50% Third Parties – 50%
La Porte Pipeline Company, L.P.	Texas	Enterprise Products Operating LLC – 49.5% La Porte Pipeline GP, LLC – 1.0% Third Party – 49.5%
La Porte Pipeline GP, L.L.C.	Delaware	Enterprise Products Operating LLC – 50% Third Party – 50%
Lubrication Services, LLC	Texas	TEPPCO Crude Oil, LLC – 99.99% TEPPCO Crude GP, LLC – 0.01%

Manta Ray Gathering Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Manta Ray Offshore Gathering Company, L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. – 100%
Mapletree, LLC	Delaware	Enterprise Products Operating LLC – 100%
MCN Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
MCN Pelican Interstate Gas, LLC	Delaware	Acadian Gas, LLC – 100%
Mid-America Pipeline Company, LLC	Delaware	Mapletree, LLC – 100%
Mont Belvieu Caverns, LLC	Delaware	Enterprise Products Operating LLC – 33.365% Enterprise Products OLPGP, Inc. – 0.635% DEP Operating Partnership, L.P. – 66%
Moray Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 100%
Nautilus Pipeline Company, L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. – 100%
Neches Pipeline System	Delaware	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Nemo Gathering Company, LLC	Delaware	Moray Pipeline Company, LLC – 33.92% Third Party – 66.08%
Neptune Pipeline Company, L.L.C.	Delaware	Sailfish Pipeline Company, L.L.C. – 25.67% Third Parties – 74.33%
Norco-Taft Pipeline, LLC	Delaware	Enterprise NGL Private Lines & Storage, LLC – 100%
Olefins Terminal Corporation	Delaware	E-Cypress, LLC – 100%
Panola Pipeline Company, LLC	Texas	TEPPCO Midstream Companies, LLC – 99.999% TEPPCO NGL Pipelines, LLC – 0.001%
Petal Gas Storage, L.L.C.	Delaware	Crystal Holding, L.L.C. – 100%
Pontchartrain Natural Gas System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Port Neches GP LLC	Texas	Enterprise Products Operating LLC – 100%
Port Neches Pipeline LLC	Texas	Enterprise Products Operating LLC – 99% Port Neches GP LLC – 1%
Poseidon Oil Pipeline Company, L.L.C.	Delaware	Poseidon Pipeline Company, L.L.C. – 36% Third Parties – 64%
Poseidon Pipeline Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Propylene Pipeline Partnership, L.P.	Texas	Enterprise Products Operating LLC – 99% Enterprise Products OLPGP, Inc. – 1%
QP-LS, LLC	Wyoming	Lubrication Services, LLC – 100%
Quanah Pipeline Company, LLC	Texas	TEPPCO Midstream Companies, LLC – 99.999% TEPPCO NGL Pipelines, LLC – 0.001%
Rio Grande Pipeline Company	Texas	Enterprise Products Operating Company – 70% Third Party – 30%
Sabine Propylene Pipeline L.P.	Texas	Enterprise Products Operating LLC – 33% Propylene Pipeline Partnership L.P. – 1% DEP Operating Partnership, L.P. – 66%
Sailfish Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 100%
SB Asset Holdings, LLC	Delaware	Enterprise Products Operating LLC – 100%
Seaway Crude Pipeline Company	Texas	TEPPCO Seaway, L.P. – 50% Third Parties – 50%
Seminole Pipeline Company	Delaware	E-Oaktree, LLC – 80% E-Cypress, LLC – 10% Third Party – 10%
Sorrento Pipeline Company, LLC	Texas	Enterprise Products Operating LLC – 100%

South Texas NGL Pipelines, LLC	Delaware	Enterprise Products Operating LLC – 34% DEP Operating Partnership, L.P. – 66%
TCTM, L.P.	Delaware	TEPPCO Partners, L.P. – 99.999% TEPPCO GP, LLC – 0.001%
TE Products Pipeline Company, LLC	Texas	TEPPCO Partners, L.P. – 99.999% TEPPCO GP, LLC – 0.001%
TECO Gas Gathering LLC	Delaware	Enterprise Products Operating LLC – 100%
TECO Gas Processing LLC	Delaware	Enterprise Products Operating LLC – 100%
Tejas-Magnolia Energy, LLC	Delaware	Pontchartrain Natural Gas System – 96.6% MCN Pelican Interstate Gas, LLC – 3.4%
TEPPCO Colorado, LLC	Delaware	TEPPCO Midstream Companies, LLC – 100%
TEPPCO Crude GP, LLC	Delaware	TCTM, L.P. – 100%
TEPPCO Crude Oil, LLC	Texas	TCTM, L.P. – 99.99% TEPPCO Crude GP, LLC – 0.01%
TEPPCO Crude Pipeline, LLC	Texas	TCTM, L.P. – 99.99% TEPPCO Crude GP, LLC – 0.01%
TEPPCO GP, LLC	Delaware	TEPPCO Partners, L.P. – 100%
TEPPCO Investments, LLC	Delaware	Texas Eastern Products Pipeline Company, LLC – 100%
TEPPCO Midstream Companies, LLC	Texas	TEPPCO Partners, L.P. – 99.999% TEPPCO GP, LLC – 0.001%
TEPPCO NGL Pipelines, LLC	Delaware	TEPPCO Midstream Companies, LLC – 100%
TEPPCO O/S Port System, LLC	Texas	TEPPCO Crude GP, LLC – 100%
TEPPCO Partners, L.P.	Delaware	Texas Eastern Products Pipeline Company, LLC – 2% Enterprise Products Operating LLC – 98%
TEPPCO Seaway, L.P.	Delaware	TEPPCO Crude Pipeline, LLC – 99.99% TEPPCO Crude GP, LLC – 0.01%
TEPPCO Terminaling and Marketing Company LLC	Delaware	TE Products Pipeline Company, LLC – 100%
TEPPCO Terminals Company, L.P.	Delaware	TE Products Pipeline Company, LLC – 99.999% TEPPCO GP, LLC – 0.001%
Texas Eastern Products Pipeline Company, LLC	Delaware	Enterprise Products Operating LLC – 100%
Tri-States NGL Pipeline, L.L.C.	Delaware	Enterprise Products Operating LLC – 50% Enterprise NGL Pipelines, LLC – 33.3% Third Party – 16.67%
TXO-Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
Val Verde Gas Gathering Company, L.P.	Delaware	TEPPCO Midstream Companies, LLC – 99.999% TEPPCO NGL Pipelines, LLC – 0.001%
Venice Energy Services Company, L.L.C.	Delaware	Enterprise Gas Processing LLC – 13.1% Third Parties – 86.99%
White River Hub, LLC	Delaware	Enterprise White River Hub, LLC – 50% Third Party – 50%
Wilcox Pipeline Company, LLC	Texas	TEPPCO Midstream Companies, LLC – 99.999% TEPPCO NGL Pipelines, LLC – 0.001%
WILPRISE Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 74.7% Third Party – 25.3%

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement No. 333-129668 of Enterprise GP Holdings L.P. on Form S-8, and (ii) Registration Statement Nos. 333-146236 and 333-161597 of Enterprise GP Holdings L.P. on Form S-3 of our reports dated March 1, 2010, relating to the consolidated financial statements of Enterprise GP Holdings L.P. and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the retroactive effects of the common control acquisition of TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC by Enterprise Products Partners L.P. on October 26, 2009 and the related change in business segments described in Notes 1 and 11), and the effectiveness of Enterprise GP Holdings L.P. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Enterprise GP Holdings L.P. for the year ended December 31, 2009.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 24, 2010, with respect to the consolidated financial statements of Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2009 and 2008 and for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007, which report is included in the Annual Report of Enterprise GP Holdings L.P. on Form 10-K for the year ended December 31, 2009. We hereby consent to the incorporation by reference of said report in the Registration Statements of Enterprise GP Holdings L.P. on Forms S-3 (File No. 333-146236 and File No. 333-161597) and on Form S-8 (File No. 333-129668).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 1, 2010

EXHIBIT 31.1

CERTIFICATIONS

I, Dr. Ralph S. Cunningham that:

1. I have reviewed this annual report on Form 10-K of Enterprise GP Holdings 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.

Date: March 1, 2010

/s/ Dr. Ralph S. Cunningham

Name: Dr. Ralph S. Cunningham
Title: Chief Executive Officer of EPE Holdings, LLC, the General Partner of Enterprise GP Holdings L.P.

EXHIBIT 31.2

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise GP Holdings 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.

Date: March 1, 2010

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of EPE Holdings, LLC,
the General Partner of Enterprise GP Holdings L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF DR. RALPH S. CUNNINGHAM, CHIEF EXECUTIVE OFFICER OF EPE HOLDINGS, LLC, THE GENERAL PARTNER OF ENTERPRISE GP HOLDINGS L.P.

In connection with this annual report of Enterprise GP Holdings L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Dr. Ralph S. Cunningham, Chief Executive Officer of EPE Holdings, LLC, the General Partner of the Registrant, 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) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Dr. Ralph S. Cunningham

Name: Dr. Ralph S. Cunningham
Title: Chief Executive Officer of EPE Holdings, LLC,
the General Partner of Enterprise GP Holdings L.P.

Date: March 1, 2010

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF EPE HOLDINGS, LLC, THE GENERAL PARTNER OF ENTERPRISE GP HOLDINGS L.P.

In connection with this annual report of Enterprise GP Holdings L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of EPE Holdings, LLC, the General Partner of the Registrant, 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) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of EPE Holdings, LLC
the General Partner of Enterprise GP Holdings L.P.

Date: March 1, 2010

EXHIBIT 99.1

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Equity, L.P. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Energy Transfer Equity, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Equity, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Equity, L.P. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Partnership retrospectively adopted a new accounting pronouncement on January 1, 2009 related to the accounting for noncontrolling interests in consolidated financial statements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Energy Transfer Equity, L.P.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 24, 2010 (not separately included herein), expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 24, 2010

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 68,315	$ 92,023
Marketable securities	6,055	5,915
Accounts receivable, net of allowance for doubtful accounts	566,522	591,257
Accounts receivable from related companies	51,894	15,142
Inventories	389,954	272,348
Exchanges receivable	23,136	45,209
Price risk management assets	12,371	5,423
Other current assets	149,712	153,678
Total current assets	1,267,959	1,180,995
PROPERTY, PLANT AND EQUIPMENT, net	9,064,475	8,702,534
ADVANCES TO AND INVESTMENT IN AFFILIATES	663,298	10,110
GOODWILL	775,094	773,283
INTANGIBLES AND OTHER ASSETS, net	389,683	402,980
Total assets	$ 12,160,509	$ 11,069,902

The accompanying notes are an integral part of these consolidated financial statements.

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2009	December 31, 2008
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 359,176	$ 381,933
Accounts payable to related companies	38,515	34,495
Exchanges payable	19,203	54,636
Price risk management liabilities	65,146	142,432
Interest payable	137,708	115,487
Accrued and other current liabilities	229,073	434,706
Current maturities of long-term debt	40,924	45,232
Total current liabilities	889,745	1,208,921
LONG-TERM DEBT, less current maturities	7,750,998	7,190,357
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	73,332	121,710
DEFERRED INCOME TAXES	204,373	194,871
OTHER NON-CURRENT LIABILITIES	21,810	14,727
COMMITMENTS AND CONTINGENCIES (Note 11)		
	8,940,258	8,730,586
EQUITY:		
PARTNERS' CAPITAL (DEFICIT):		
General Partner	368	155
Limited Partners:		
Common Unitholders (222,898,248 and 222,829,956 units authorized, issued and outstanding at December 31, 2009 and 2008, respectively)	53,412	(15,762)
Accumulated other comprehensive loss	(53,628)	(67,825)
Total partners' capital (deficit)	152	(83,432)
Noncontrolling interest	3,220,099	2,422,748
Total equity	3,220,251	2,339,316
Total liabilities and equity	$ 12,160,509	$ 11,069,902

The accompanying notes are an integral part of these consolidated financial statements.

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
REVENUES:				
Natural gas operations	$ 4,115,806	$ 7,653,156	$ 1,832,192	$ 5,385,892
Retail propane	1,190,524	1,514,599	471,494	1,179,073
Other	110,965	125,612	45,656	227,072
Total revenues	5,417,295	9,293,367	2,349,342	6,792,037
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	2,519,575	5,885,982	1,343,237	4,207,700
Cost of products sold - retail propane	574,854	1,014,068	315,698	734,204
Cost of products sold - other	27,627	38,030	14,719	136,302
Operating expenses	680,893	781,831	221,757	559,600
Depreciation and amortization	325,024	274,372	75,406	191,383
Selling, general and administrative	178,924	200,181	61,874	153,512
Total costs and expenses	4,306,897	8,194,464	2,032,691	5,982,701
OPERATING INCOME	1,110,398	1,098,903	316,651	809,336
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(468,420)	(357,541)	(103,375)	(279,986)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	33,619	(128,423)	(28,683)	29,081
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	1,913	8,115	(13,327)	1,129
INCOME BEFORE INCOME TAX EXPENSE	707,100	683,562	192,758	563,359
Income tax expense	9,229	3,808	9,949	11,391
NET INCOME	697,871	679,754	182,809	551,968
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	255,398	304,710	90,132	232,608
NET INCOME ATTRIBUTABLE TO PARTNERS	442,473	375,044	92,677	319,360
GENERAL PARTNER'S INTEREST IN NET INCOME	1,370	1,161	287	1,048
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 441,103	$ 373,883	$ 92,390	$ 318,312
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.98	$ 1.68	$ 0.41	$ 1.56
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	222,898,203	222,829,956	222,829,916	204,578,719
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.98	$ 1.68	$ 0.41	$ 1.55
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	222,898,203	222,829,956	222,829,916	204,578,719

The accompanying notes are an integral part of these consolidated financial statements.

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income	$ 697,871	$ 679,754	$ 182,809	$ 551,968
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	16,958	(22,916)	(17,970)	(163,378)
Change in value of derivative instruments accounted for as cash flow hedges	(11,017)	(40,350)	(2,221)	179,861
Change in value of available-for-sale securities	10,923	(6,418)	(98)	280
	16,864	(69,684)	(20,289)	16,763
Comprehensive income	714,735	610,070	162,520	568,731
Less: Comprehensive income attributable to noncontrolling interest	258,066	291,624	92,832	239,885
Comprehensive income attributable to partners	$ 456,669	$ 318,446	$ 69,688	$ 328,846

The accompanying notes are an integral part of these consolidated financial statements.

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in thousands)

	General Partner	Common Unitholders	Class B Unitholders	Class C Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, August 31, 2006	$ (69)	$ (9,586)	$ 53,130	$ -	$ 2,276	$ 1,439,127	$ 1,484,878
Unit issuances	-	372,638	-	4,456	-	(4,456)	372,638
Equity issue costs of Class C Units	-	-	-	(204)	-	-	(204)
Assumption of related company debt	-	-	-	(70,500)	-	-	(70,500)
Distribution to partners	(955)	(246,136)	(1,645)	(28,261)	-	-	(276,997)
Subsidiary distributions and other	-	-	-	-	-	(252,584)	(252,584)
Purchase premium on ETP Class G Units	-	(451,150)	-	-	-	451,150	-
Tax effect of remedial income allocation from tax amortization of goodwill	-	-	-	-	-	(1,161)	(1,161)
Non-cash unit-based compensation expense	-	28	-	-	-	10,471	10,499
Other comprehensive income, net of tax	-	-	-	-	9,486	7,277	16,763
Net income	1,048	260,184	2,524	55,604	-	232,608	551,968
Conversion to Common Units	-	15,104	(54,009)	38,905	-	-	-
Balance, August 31, 2007	24	(58,918)	-	-	11,762	1,882,432	1,835,300
Distributions to partners	(270)	(86,904)	-	-	-	-	(87,174)
Subsidiary distributions and other	-	-	-	-	-	(63,756)	(63,756)
Tax effect of remedial income allocation from tax amortization of goodwill	-	-	-	-	-	(1,161)	(1,161)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	-	23	-	-	-	7,950	7,973
Non-cash executive compensation expense	-	-	-	-	-	1,167	1,167
Subsidiary sale of common units	151	48,781	-	-	-	187,355	236,287
Other comprehensive loss, net of tax	-	-	-	-	(22,989)	2,700	(20,289)
Net income	287	92,390	-	-	-	90,132	182,809
Balance, December 31, 2007	192	(4,628)	-	-	(11,227)	2,106,819	2,091,156
Distributions to partners	(1,349)	(434,519)	-	-	-	-	(435,868)
Subsidiary distributions	-	-	-	-	-	(319,963)	(319,963)
Tax effect of remedial income allocation from tax amortization of goodwill	-	-	-	-	-	(3,407)	(3,407)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	-	823	-	-	-	19,968	20,791
Non-cash executive compensation expense	-	48	-	-	-	1,202	1,250
Subsidiary sale of common units	151	48,631	-	-	-	326,505	375,287
Other comprehensive loss, net of tax	-	-	-	-	(56,598)	(13,086)	(69,684)
Net income	1,161	373,883	-	-	-	304,710	679,754
Balance, December 31, 2008	155	(15,762)	-	-	(67,825)	2,422,748	2,339,316
Distributions to ETE partners	(1,457)	(469,201)	-	-	-	-	(470,658)
Subsidiary distributions	-	-	-	-	-	(381,471)	(381,471)
Subsidiary sale of common units	300	96,696	-	-	-	902,680	999,676
Tax effect of remedial income allocation from tax amortization of goodwill	-	-	-	-	-	(3,762)	(3,762)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	-	551	-	-	-	20,613	21,164
Non-cash executive compensation expense	-	25	-	-	-	1,225	1,250
Other comprehensive loss, net of tax	-	-	-	-	14,197	2,668	16,865
Net income	1,370	441,103	-	-	-	255,398	697,871
Balance, December 31, 2009	$ 368	$ 53,412	$ -	$ -	$ (53,628)	$ 3,220,099	$ 3,220,251

The accompanying notes are an integral part of these consolidated financial statements.

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 697,871	$ 679,754	$ 182,809	$ 551,968
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	325,024	274,372	75,406	191,383
Amortization of finance costs charged to interest	14,954	10,962	2,441	6,691
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Goodwill impairment	-	11,359	-	-
Non-cash unit-based compensation expense	24,583	24,304	8,137	10,499
Non-cash executive compensation expense	1,250	1,250	442	-
Deferred income taxes	8,422	(8,177)	37	(6,939)
(Gains) losses on disposal of assets	1,564	1,303	(14,310)	6,310
Distribution in excess of (less than) earnings of affiliates, net	3,224	5,621	4,448	(5,161)
Other non-cash	(4,468)	3,382	(2,069)	(760)
Net change in operating assets and liabilities, net of effects of acquisitions	(351,955)	131,575	(49,250)	248,100
Net cash provided by operating activities	723,461	1,143,720	208,635	1,006,320
CASH FLOWS FROM INVESTING ACTIVITIES:				
Net cash (paid for) received in acquisitions	30,367	(84,783)	(337,092)	(90,695)
Capital expenditures	(748,621)	(2,054,806)	(651,228)	(1,107,127)
Contributions in aid of construction costs	6,453	50,050	3,493	10,463
(Advances to) repayments from affiliates	(655,500)	54,534	(32,594)	(993,866)
Proceeds from the sale of assets	21,545	19,420	21,478	23,135
Net cash used in investing activities	(1,345,756)	(2,015,585)	(995,943)	(2,158,090)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	3,542,612	6,205,994	1,742,802	6,010,633
Principal payments on debt	(3,020,587)	(4,890,619)	(1,062,272)	(4,628,052)
Net proceeds from issuance of Common Units	-	-	-	372,434
Subsidiary equity offerings, net of issue costs	936,337	373,059	234,887	-
Distributions to partners	(470,658)	(435,868)	(87,174)	(276,997)
Debt issuance costs	(7,646)	(25,272)	(211)	(23,279)
Distributions to noncontrolling interests	(381,471)	(319,963)	(61,517)	(251,823)
Net cash provided by financing activities	598,587	907,331	766,515	1,202,916
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(23,708)	35,466	(20,793)	51,146
CASH AND CASH EQUIVALENTS, beginning of period	92,023	56,557	77,350	26,204
CASH AND CASH EQUIVALENTS, end of period	$ 68,315	$ 92,023	$ 56,557	$ 77,350

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts in thousands, except per unit data)

1. OPERATIONS AND ORGANIZATION:

Financial Statement Presentation

The consolidated financial statements of Energy Transfer Equity, L.P. and subsidiaries (the “Partnership”, “ETE” or the “Parent Company”) presented herein for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). We consolidate all majority-owned subsidiaries and limited partnerships, which we control as the general partner or owner of the general partner. We present equity and net income attributable to noncontrolling interest for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through February 24, 2010, the date the financial statements were issued.

The consolidated financial statements of the Partnership presented herein include the results of operations for ETE, ETE’s controlled subsidiary Energy Transfer Partners, L.P., a publicly-traded master limited partnership (“ETP”), and ETE’s wholly-owned subsidiaries: Energy Transfer Partners GP, L.P. (“ETP GP”), the General Partner of ETP, and Energy Transfer Partners, L.L.C. (“ETP LLC”), the General Partner of ETP GP. The results of operations for ETP include its wholly-owned subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“ETC OLP”); Energy Transfer Interstate Holdings, LLC (“ET Interstate”), the parent company of Transwestern Pipeline Company, LLC (“Transwestern”) and ETC Midcontinent Express Pipeline, LLC (“ETC MEP”); ETC Fayetteville Express Pipeline, LLC (“ETC FEP”); ETC Tiger Pipeline, LLC (“ETC Tiger”); Heritage Operating, L.P. (“HOLP”); Heritage Holdings, Inc. (“HHI”); and Titan Energy Partners, L.P. (“Titan”). The operations of ET Interstate are included since the date of the Transwestern acquisition on December 1, 2006. ETC FEP and ETC Tiger are included since their inception dates on August 27, 2008 and June 20, 2008, respectively. The operations of all other subsidiaries listed above are reflected for all periods presented.

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

In November 2007, we changed our fiscal year end to the calendar year. Thus, a new fiscal year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007.

We did not recast the financial data for the prior fiscal periods because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the years ended December 31, 2009 and 2008 are substantially similar to what is reflected in the information for the year ended August 31, 2007.

Certain prior period amounts have been reclassified to conform to the 2009 presentation. Other than the reclassifications related to the adoption of Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51*, which is now incorporated into ASC 810-10-65 (see Note 2), these reclassifications had no impact on net income or total equity.

Business Operations

The Parent Company currently has no separate operating activities apart from those conducted by the Operating Companies. The Parent Company's principal sources of cash flow are its direct and indirect investments in the Limited Partner and General Partner interests in ETP.

The Parent Company's primary cash requirements are for general and administrative expenses, debt service requirements and distributions to its partners. The Parent Company-only assets and liabilities of ETE are not available to satisfy the debts and other obligations of ETP and its consolidated subsidiaries. In order to fully understand the financial condition of the Partnership on a stand-alone basis, see Note 17 for stand-alone financial information apart from that of the consolidated partnership information included herein.

In order to simplify the obligations of the Partnership under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the "Operating Companies") as follows:

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, Arizona, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.

- ET Interstate, the parent company of Transwestern and ETC MEP, both of which are Delaware limited liability companies engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

- ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- ETC Tiger Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- HOLP, a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.

- Titan, a Delaware limited partnership also engaged in retail propane operations.

The Partnership, the Operating Companies and their subsidiaries are collectively referred to in this report as "we", "us", "ETE", "ETP", "Energy Transfer" or the "Partnership." References to "the Parent Company" shall mean Energy Transfer Equity, L.P. on a stand-alone basis.

ETC OLP owns an interest in and operates approximately 14,800 miles of in service natural gas gathering and intrastate transportation pipelines, three natural gas processing plants, eleven natural gas treating facilities, eleven natural gas conditioning facilities and three natural gas storage facilities located in Texas.

Revenue in our intrastate transportation and storage operations is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The intrastate transportation and storage operations also consist of the HPL System, which generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System also transports natural gas for a variety of third party customers. Our intrastate transportation and storage segment also generates revenues from fees charged for storing customers' working natural gas in our storage facilities. In addition, the use of the Bammel storage facility allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin.

Our interstate transportation operations principally focus on natural gas transportation of Transwestern, which owns and operates approximately 2,700 miles of interstate natural gas pipeline, with an additional 180 miles under construction, extending from Texas through the San Juan Basin to the California border. In addition, we have interests in joint ventures that have 500 miles of interstate natural gas pipeline and 185 miles under construction. Transwestern is a major natural gas transporter to the California border and delivers natural gas from the east end of its system to Texas intrastate and Midwest markets. The Transwestern pipeline interconnects with our existing intrastate pipelines in West Texas. The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

Revenue in our midstream operations is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines (excluding the interstate transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

Our retail propane segment sells propane and propane-related products and services. The HOLP and Titan customer base includes residential, commercial, industrial and agricultural customers.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2009 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition

Revenues for sales of natural gas, NGLs including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

Our intrastate transportation and storage and interstate transportation segments' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from the midstream segment's marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

Regulatory Accounting - Regulatory Assets and Liabilities

Transwestern, part of our interstate transportation segment, is subject to regulation by certain state and federal authorities and has accounting policies that conform to Statement of Financial Accounting Standards No. 71 (As Amended), *Accounting for the Effects of Certain Types of Regulation,* now incorporated into ASC 980, which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

As a result of our acquisition of a natural gas compression equipment business in exchange for ETP Common Units, cash acquired in connection with acquisitions during 2009 exceeded the cash we paid by $30.4 million.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Accounts receivable	$ 28,431	$ 220,635	$ (169,263)	$ 54,347
Accounts receivable from related companies	(26,321)	3,234	(12,091)	(5,376)
Inventories	(101,592)	96,145	(168,430)	196,173
Exchanges receivable	22,074	(7,888)	(4,216)	(3,406)
Other current assets	8,195	(57,150)	(4,459)	53,591
Intangibles and other assets	(4,786)	(40,753)	605	(1,817)
Accounts payable	(16,024)	(296,185)	195,574	(92,296)
Accounts payable to related companies	4,184	(13,538)	28,876	18,560
Exchanges payable	(35,433)	14,254	6,117	3,000
Accrued and other current liabilities	(124,147)	32,474	1,026	(26,794)
Interest payable	22,220	36,501	41,640	18,181
Other long-term liabilities	1,401	1,741	(680)	1,460
Price risk management liabilities, net	(130,157)	142,105	36,051	32,477
Net change in assets and liabilities, net of effect of acquisitions	$ (351,955)	$ 131,575	$ (49,250)	$ 248,100

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NON-CASH INVESTING ACTIVITIES:				
Transfer of investment in affiliate in purchase of Transwestern (Note 3)	$ -	$ -	$ -	$ 956,348
Investment in Calpine Corporation received in exchange for accounts receivable	$ -	$ 10,816	$ -	$ -
Capital expenditures accrued	$ 46,134	$ 153,230	$ 87,622	$ 43,498
Gain from subsidiary issuance of common units (recorded in partners' capital)	$ 96,996	$ 48,782	$ 48,932	$ -
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 26,237	$ 5,077	$ 3,896	$ 533,625
Subsidiary issuance of Common Units in connection with certain acquisitions	$ 63,339	$ 2,228	$ 1,400	$ -
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$ 440,492	$ 330,816	$ 79,084	$ 283,854
Cash paid for income taxes	$ 15,447	$ 5,191	$ 9,135	$ 8,962

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reflected as current assets on the consolidated balance sheets at fair value.

During the year ended December 31, 2008, we determined there was an other-than-temporary decline in the market value of one of our available-for-sale securities, and reclassified into earnings a loss of $1.4 million, which is recorded in other expense. Unrealized holding gains (losses), net of tax, of $7.4 million, $(6.4) million, $(0.1) million and $0.3 million, were recorded through accumulated other comprehensive income ("AOCI"), based on the market value of the securities, for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively. The change in value of our available-for-sale securities for the year ended December 31, 2009 includes realized losses of $3.5 million reclassified from AOCI during the period as discussed in "Accounts Receivable" below.

Accounts Receivable

Our midstream and intrastate transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. Management believes that the occurrence of bad debt in our midstream and intrastate transportation and storage segments was not significant at December 31, 2009 or 2008; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage segments was not deemed necessary.

ETP's interstate transportation operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Transwestern's management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Transwestern establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. Transwestern considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

ETP's propane operations grant credit to their customers for the purchase of propane and propane-related products. Included in accounts receivable are trade accounts receivable arising from HOLP's retail and wholesale propane and Titan's retail propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane operations are recorded as amounts are billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the propane segment is based on management's assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

We enter into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

We exchanged a portion of our outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation ("Calpine") common stock valued at $10.8 million during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock is included in marketable securities on the consolidated balance sheet at a fair value of $4.8 million as of December 31, 2008. In 2009, we sold the stock for $7.3 million and recorded a realized loss of $3.6 million, of which $3.5 million was reclassified from AOCI to other income in the consolidated statement of operations.

Accounts receivable consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas operations	$ 429,849	$ 444,816
Propane	143,011	155,191
Less – allowance for doubtful accounts	(6,338)	(8,750)
Total, net	$ 566,522	$ 591,257

The activity in the allowance for doubtful accounts consisted of the following:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Balance, beginning of the period	$ 8,750	$ 5,698	$ 5,601	$ 4,000
Accounts receivable written off, net of recoveries	(5,404)	(4,963)	(447)	(2,628)
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Balance, end of period	$ 6,338	$ 8,750	$ 5,698	$ 5,601

Inventories

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 157,103	$ 184,727
Propane	66,686	63,967
Appliances, parts and fittings and other	166,165	23,654
Total inventories	$ 389,954	$ 272,348

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheet and have been recorded in cost of products sold in our consolidated statements of operations.

During 2009, we recorded lower of cost or market adjustments of $54.0 million, which were offset by fair value adjustments related to our application of fair value hedging of $66.1 million.

During 2008, we recorded lower-of-cost-or-market adjustments of $69.5 million for natural gas inventory and $4.4 million for propane inventory to reflect market values, which were less than the weighted-average cost. The natural gas inventory adjustment in 2008 was partially offset in net income by the recognition of unrealized gains on related cash flow hedges in the amount of $21.7 million from AOCI.

Exchanges

The midstream and intrastate transportation and storage segments' exchanges consist of natural gas and NGL delivery imbalances with others. These amounts, which are valued at market prices, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. Management believes market value approximates cost.

The interstate transportation segment's natural gas imbalances occur as a result of differences in volumes of gas received and delivered. Transwestern records natural gas imbalances for in-kind receivables and payables at the dollar weighted composite average of all current month gas transactions and dollar valued imbalances are recorded at contractual prices.

Other Current Assets

Other current assets consisted of the following:

	December 31, 2009	December 31, 2008
Deposits paid to vendors	$ 79,694	$ 78,237
Prepaid and other	70,018	75,441
Total other current assets	$ 149,712	$ 153,678

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or Federal Energy Regulatory Commission ("FERC") mandated lives of the assets. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the installation of company-owned propane tanks and construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our results of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of long-lived assets was required during the periods presented.

Capitalized interest is included for pipeline construction projects, except for interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of ETP's revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2009	December 31, 2008
Land and improvements	$ 87,388	$ 74,895
Buildings and improvements (10 to 40 years)	160,912	133,951
Pipelines and equipment (10 to 83 years)	7,388,889	5,592,057
Natural gas storage (40 years)	100,746	92,457
Bulk storage, equipment and facilities (3 to 83 years)	591,908	533,621
Tanks and other equipment (10 to 30 years)	602,915	578,118
Vehicles (3 to 10 years)	176,946	156,486
Right of way (20 to 83 years)	516,709	366,205
Furniture and fixtures (3 to 10 years)	32,810	28,075
Linepack	53,404	48,108
Pad gas	47,363	53,583
Other (5 to 10 years)	117,896	97,975
	9,877,886	7,755,531
Less – Accumulated depreciation	(1,052,566)	(762,014)
	8,825,320	6,993,517
Plus – Construction work-in-process	239,155	1,709,017
Property, plant and equipment, net	$ 9,064,475	$ 8,702,534

We recognized the following amounts of depreciation expense, capitalized interest, and AFUDC for the periods presented:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Depreciation expense	$ 304,129	$ 256,910	$ 68,642	$ 175,851
Capitalized interest, excluding AFUDC	$ 11,791	$ 21,595	$ 12,657	$ 22,979
AFUDC (both debt and equity components)	$ 10,237	$ 50,074	$ 5,095	$ 3,600

Advances to and Investment in Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we have a 20% to 50% ownership and exercise significant influence over, but do not control the investee's operating and financial policies.

We account for our investments in Midcontinent Express Pipeline LLC and Fayetteville Express Pipeline LLC using the equity method. See Note 4 for a discussion of these joint ventures.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of December 31 for subsidiaries in our interstate segment and as of August 31 for all others. At December 31, 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No other goodwill impairments were recorded for the periods presented in these consolidated financial statements. Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation	Midstream	Retail Propane	All Other	Total
Balance as of December 31, 2007	$ 10,327	$ 98,613	$ 24,368	$ 594,801	$ 29,589	$ 757,698
Purchase accounting adjustments	-	-	-	2,457	-	2,457
Goodwill acquired	-	-	9,141	15,346	-	24,487
Goodwill impairment	-	-	(11,359)	-	-	(11,359)
Balance as of December 31, 2008	10,327	98,613	22,150	612,604	29,589	773,283
Purchase accounting adjustments	-	-	-	(8,662)	-	(8,662)
Goodwill acquired	-	-	-	33	10,440	10,473
Balance as of December 31, 2009	$ 10,327	$ 98,613	$ 22,150	$ 603,975	$ 40,029	$ 775,094

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

Intangibles and Other Assets

Intangibles and other assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other assets were as follows:

	December 31, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (3 to 15 years)	$ 24,139	$ (12,415)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,843	(53,123)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(5,638)	23,015	(3,744)
Patents (9 years)	750	(35)	-	-
Other (10 years)	478	(397)	2,677	(2,244)
Total amortizable intangible assets	202,225	(71,608)	210,330	(70,092)
Non-amortizable intangible assets:				
Trademarks	75,825	-	75,667	-
Total intangible assets	278,050	(71,608)	285,997	(70,092)
Other assets:				
Financing costs (3 to 30 years)	84,099	(34,702)	74,611	(23,508)
Regulatory assets	101,879	(9,501)	98,560	(5,941)
Other assets	41,466	-	43,353	-
Total intangibles and other assets	$ 505,494	$ (115,811)	$ 502,521	$ (99,541)

Aggregate amortization expense of intangible and other assets are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Reported in depreciation and amortization	$ 20,895	$ 17,462	$ 6,764	$ 15,532
Reported in interest expense	$ 11,195	$ 9,015	$ 2,716	$ 7,132

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2010	$ 29,962
2011	27,553
2012	22,117
2013	16,310
2014	15,343

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate segment and as of August 31 for all others. No impairment of intangible assets was required during the periods presented in these consolidated financial statements.

Asset Retirement Obligation

We record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, we also recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

We have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates. However, management was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2009 or 2008 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2009	December 31, 2008
Customer advances and deposits	$ 88,430	$ 106,679
Accrued capital expenditures	46,134	153,230
Accrued wages and benefits	25,577	65,754
Taxes other than income taxes	23,294	20,772
Income taxes payable	3,154	14,298
Deferred income taxes	-	589
Other	42,484	73,384
Total accrued and other current liabilities	$ 229,073	$ 434,706

Customer Advances and Deposits

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Fair Value of Financial Instruments

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at December 31, 2009 was $8.25 billion and $7.79 billion, respectively. At December 31, 2008, the aggregate fair value and carrying amount of long-term debt was $6.41 billion and $7.24 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. We currently do not have any fair value measurements that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations.

The following table summarizes the fair value of our financial assets and liabilities as of December 31, 2009 and 2008 based on inputs used to derive their fair values:

	Fair Value Measurements at at December 31, 2009 Using			Fair Value Measurements at December 31, 2008 Using		
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets:						
Marketable securities	$ 6,055	$ 6,055	$ -	$ 5,915	$ 5,915	$ -
Inventories	156,156	156,156	-	-	-	-
Commodity derivatives	32,479	20,090	12,389	111,513	106,090	5,423
Liabilities:						
Commodity derivatives	(8,016)	(7,574)	(442)	(43,336)	-	(43,336)
Interest rate swap derivatives	(138,036)	-	(138,036)	(220,806)	-	(220,806)
	$ 48,638	$ 174,727	$ (126,089)	$ (146,714)	$ 112,005	$ (258,719)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized. In March 2008, we received a reimbursement related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million, which is recorded in other income on our consolidated statement of operations for the year ended December 31, 2008.

Contributions in aid of construction costs were as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Received and netted against project costs	$ 6,453	$ 50,050	$ 3,493	$ 10,463
Recorded in other income	(305)	8,352	216	403
Total	$ 6,148	$ 58,402	$ 3,709	$ 10,866

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and totaled $55.9 million and $112.0 million for the years ended December 31, 2009 and 2008, respectively, $30.7 million for the four months ended December 31, 2007, and $58.6 million for the year ended August 31, 2007. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to governmental authorities on a net basis.

Issuances of Subsidiary Units

We record changes in our ownership interest of our subsidiaries as equity transactions, with no gain or loss recognized in consolidated net income or comprehensive income. For example, upon ETP's issuance of ETP Common Units in a public offering, we record any difference between the amount of consideration received or paid and the amount by which the noncontrolling interest is adjusted as a change in partners' capital.

Income Taxes

ETE is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under the Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

Our partnership will be considered to have terminated for federal income tax purposes if transfers of units within a 12-month period constitute the sale or exchange of 50% or more of our capital and profits interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of our capital and profits interests within the prior 12-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

We exceeded the 50% threshold on May 7, 2007, and, as a result, our partnership terminated for federal tax income purposes on that date. Our termination also caused ETP to terminate for federal income tax purposes on that date. These terminations did not affect our classification or the classification of ETP as a partnership for federal income tax purposes or otherwise affect the nature or extent of our "qualifying income" or the "qualifying income" of ETP for federal income tax purposes. These terminations required both us and ETP to close our taxable years and to make new elections as to various tax matters. In addition, ETP was required to reset the depreciation schedule for its depreciable assets for federal income tax purposes. The resetting of ETP's depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to the Unitholders of ETP and, consequently, to our Unitholders. However, elections ETP and ETE made with respect to the amortization of certain intangible assets had the effect of reducing the amount of taxable income that would otherwise be allocated to ETE Unitholders.

As a result of the tax termination discussed above, we elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, ETP's subsidiary, Heritage Holdings, Inc. ("HHI"), which owns ETP's Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of ETP Common Units. The amount of such "goodwill" accumulated as of the date of ETP's acquisition of HHI (approximately $158.0 million) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. ETP accounts for HHI using the treasury stock method due to its ownership of ETP's Class E units. ETP accounts for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of ETP's HHI purchase price allocation, which effectively results in a charge to ETP's common equity and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the years ended December 31, 2009 and 2008, the four months ended December, 31, 2007, and the year ended August 31, 2007, this resulted in a current tax expense and deferred tax benefit (with a corresponding charge to common equity as an adjustment of the purchase price allocation) of approximately $3.8 million, $3.4 million, $1.2 million and $1.2 million, respectively. As of December 31, 2009, the amount of tax goodwill to be amortized over the next 13 years for which HHI will receive a remedial income allocation is approximately $132.8 million.

As a limited partnership, we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries ("C corporations"). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, our non-qualifying income did not exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes, under which deferred income taxes are recorded based upon differences between the financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

Accounting for Derivative Instruments and Hedging Activities

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention gas and hedge location price differentials related to the transportation of natural gas.

- Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We are exposed to market risk for changes in interest rates related to our revolving credit facilities. We previously have managed a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not accounted for as cash flow hedges are classified in other income.

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, our Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 7).

Unit-Based Compensation

We recognize compensation expense for equity awards issued to employees over the vesting period based on the grant-date fair value. The grant-date fair value is determined based on the market price of our Common Units on the grant date, adjusted to reflect the present value of any expected distributions that will not accrue to the employee during the vesting period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected unit distributions based on the most recently declared distributions as of the grant date.

New Accounting Standards

Accounting Standards Codification. On July 1, 2009, the Financial Accounting Standards Board ("FASB") instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental U.S. generally accepted accounting principles ("GAAP"). The FASB Accounting Standards Codification ("ASC") is now the single authoritative source for GAAP. Although the implementation of ASC has no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Noncontrolling Interests. On January 1, 2009, we adopted SFAS 160, now incorporated into ASC 810-10, which established new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, the new standard requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent's equity. The amount of net income attributable to the noncontrolling interest is included in consolidated net income on the face of the income statement. The new standard clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, the new standard requires that a parent recognizes a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss is measured using the fair value of the noncontrolling equity investment on the deconsolidation date. This standard also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. The adoption of this standard did not have a significant impact on our financial position or results of operations. However, it did result in certain changes to our financial statement presentation, including the change in classification of noncontrolling interest (minority interest) from liabilities to equity on the condensed consolidated balance sheet.

Upon adoption, we reclassified $2.42 billion from minority interest liability to noncontrolling interest as a separate component of equity in our consolidated balance sheet as of December 31, 2008. In addition, we reclassified $304.7 million, $90.1 million and $232.6 million of minority interest expense to net income attributable to noncontrolling interest in our consolidated statements of operations for the year ended December 31, 2008, the four month transition period ended December 31, 2007 and the year ended August 31, 2007. Net income per limited partner unit has not been affected as a result of the adoption of this standard.

Earnings per Unit. On January 1, 2009, we adopted a new methodology for calculating earnings per unit to reflect recently ratified changes to accounting standards. This new standard was originally issued as Emerging Issues Task Force Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*, and is now incorporated into ASC 260-10. Our adoption of this standard did not have an impact on the calculation of ETE's earnings per unit.

On January 1, 2009, we also adopted FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which is now incorporated into ASC 260-10. This standard clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. Based on unvested unit awards outstanding at the time of adoption, application of this standard did not have a material impact on our computation of earnings per unit.

Business Combinations. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations*, which is now incorporated into ASC 805. The new standard significantly changes the accounting for business combinations and includes a substantial number of new disclosure requirements. The new standard requires an acquiring entity to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions and changes the accounting treatment for certain specific items, including:

- Acquisition costs are generally expensed as incurred;
- Noncontrolling interests (previously referred to as "minority interests") are valued at fair value at the acquisition date;
- In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;

- Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and

- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

Our adoption of this standard did not have an immediate impact on our financial position or results of operations; however, it has impacted the accounting for our business combinations subsequent to adoption.

Derivative Instruments and Hedging Activities. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133*, which is now incorporated into ASC 815. This standard changed the disclosure requirements for derivative instruments and hedging activities, including requirements for qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The standard only affected disclosure requirements; therefore, our adoption did not impact our financial position or results of operations.

Equity Method Investment Accounting. On January 1, 2009, we adopted Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations*, which is now incorporated into ASC 323-10. This standard establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment, and also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. Our adoption did not have a material impact on our financial position or results of operations.

Subsequent Events. During 2009, we adopted Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events*, which is now incorporated into ASC 855. Under this standard, we are required to evaluate subsequent events through the date that our financial statements are issued and also required to disclose the date through which subsequent events are evaluated. The adoption of this standard does not change our current practices with respect to evaluating, recording and disclosing subsequent events; therefore, our adoption of this statement during the second quarter had no impact on our financial position or results of operations.

3. ACQUISITIONS:

Proposed Transaction

We have agreed to purchase a natural gas gathering company which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale. The purchase price is $150 million in cash, excluding certain adjustments as defined in the purchase agreement, and the acquisition is expected to close in March 2010.

2009

In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas, in exchange for the issuance of 1,450,076 ETP Common Units having an aggregate market value of approximately $63.3 million on the closing date. In connection with this transaction, we received cash of $41.1 million, assumed total liabilities of $30.5 million, which includes $8.4 million in notes payable and recorded goodwill of $8.7 million. In addition, we acquired ETG in August 2009. See Note 14.

2008

During the year ended December 31, 2008, HOLP and Titan collectively acquired substantially all of the assets of 20 propane businesses. The aggregate purchase price for these acquisitions totaled $96.4 million, which included $76.2 million of cash paid, net of cash acquired, liabilities assumed of $ 8.2 million, 53,893 Common Units issued valued at $2.2 million and debt forgiveness of $9.8 million. The cash paid for acquisitions was financed primarily with ETP's and HOLP's Senior Revolving Credit Facilities. We recorded $15.3 million of goodwill in connection with these acquisitions.

Transition Period 2007

Canyon Acquisition

In October 2007, ETP acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the "Canyon acquisition") for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The purchase price was initially allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. We completed the purchase price allocation during the third quarter of 2008. The adjustments to the purchase price allocation were not material.

The final allocations of the purchase price are noted below:

Accounts receivable	$	3,613
Inventory		183
Prepaid and other current assets		1,606
Property, plant, and equipment		284,910
Intangibles and other assets		6,351
Goodwill		11,359
Total assets acquired		308,022
Accounts payable		(1,840)
Customer advances and deposits		(1,030)
Total liabilities assumed		(2,870)
Net assets acquired	$	305,152

2007

On November 1, 2006, the Parent Company acquired from Energy Transfer Investments, L.P. ("ETI", a partnership also controlled by LE GP) the remaining 50% of the Class B Limited Partner interests in ETP GP owned by ETI. The Parent Company recorded this acquisition at ETI's historical cost of $4.5 million as required under GAAP due to the fact that the Parent Company and ETI are companies under common control. As a result, the Parent Company now owns 100% of the Incentive Distribution Rights of ETP. The acquisition was effected through the issuance of 83,148,900 newly created Parent Company Class C Units and the assumption by the Parent Company of approximately $70.5 million of ETI's indebtedness. The assumption of this debt represents a non-cash financing activity. The Class C Units were recorded at the net value of the debt assumption (accounted for as a distribution to ETI) and the value of the ETP GP Class B Units acquired, a net amount of $66.0 million. The Class C Units had essentially the same voting rights and rights to distributions as the Common Units and Class B Units. The Class C Units converted into Common Units upon approval by the ETE Common Unitholders on February 22, 2007.

Also on November 1, 2006, the Parent Company acquired additional limited partner interests in ETP (Class G Units, which subsequently converted to Common Units on May 1, 2007, see Note 7) which increased the Parent Company's aggregate ownership in ETP's limited partner interests to approximately 46%.

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services ("GE") and Southern Union Company ("Southern Union"), ETP acquired the member interests in CCE Holdings, LLC ("CCEH") from GE and certain other investors for $1.00 billion. ETP financed a portion of the CCEH purchase price with the proceeds from its issuance of 26,086,957 Class G Units to the Parent Company simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP's 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern, which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and formed the interstate transportation segment of ETP.

The total acquisition cost for Transwestern, net of cash acquired, was as follows:

Basis of investment in CCEH at November 30, 2006	$	956,348
Distributions received on December 1, 2006		(6,217)
Fair value of short-term debt assumed		13,000
Fair value of long-term debt assumed		519,377
Other assumed long-term indebtedness		10,096
Current liabilities assumed		35,781
Cash acquired		(3,386)
Acquisition costs incurred		11,696
Total	$	1,536,695

In September 2006, ETP acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of approximately $30.6 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas and are included in our midstream operating segment. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility. In March 2008, a contingent payment of $8.7 million was recorded as an adjustment to goodwill in the midstream segment.

In December 2006, ETP purchased a natural gas gathering system in north Texas for $32.0 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $21.0 million to be determined two years after the closing date. In December 2008, it was determined that a contingency payment would not be required. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility.

During the fiscal year ended August 31, 2007, HOLP and Titan collectively acquired substantially all of the assets of five propane businesses. The aggregate purchase price for these acquisitions totaled $17.6 million, which included $15.5 million of cash paid, net of cash acquired, and liabilities assumed of $2.1 million. The cash paid for acquisitions was financed primarily with ETP's and HOLP's Senior Revolving Credit Facilities.

Except for the acquisition of the interests in ETP GP, the purchase of Class G Units from ETP and the 50% member interests in CCEH, the acquisitions discussed above were accounted for under the purchase method of accounting and the purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. The acquisition of 100% of Transwestern has been accounted for under the purchase method of accounting since the acquisition on December 1, 2006. The acquisition of the interests in ETP GP was accounted for on the basis of historical costs, as discussed above. The purchase of Class G Units from ETP was accounted for as described in Note 7.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for the fiscal year 2007 acquisitions described above, net of cash acquired:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$ -	$ 20,062	$ 1,111
Inventory	-	895	414
Prepaid and other current assets	-	11,842	57
Investment in unconsolidated affiliate	(503)	-	-
Property, plant, and equipment	50,916	1,254,968	8,035
Intangibles and other assets	23,015	141,378	3,808
Goodwill	-	107,550	4,167
Total assets acquired	73,428	1,536,695	17,592
Accounts payable	-	(1,932)	(381)
Customer advances and deposits	-	(700)	(254)
Accrued and other current liabilities	(292)	(33,149)	(170)
Short-term debt (paid in December 2006)	-	(13,000)	-
Long-term debt	-	(519,377)	(1,309)
Other long-term obligations	-	(10,096)	-
Total liabilities assumed	(292)	(578,254)	(2,114)
Net assets acquired	$ 73,136	$ 958,441	$ 15,478

The purchase price for the acquisitions was initially allocated based on the estimated fair value of the assets acquired and liabilities assumed. The Transwestern allocation was based on the preliminary results of independent appraisals. The purchase price allocations were completed during the first quarter of 2008. The final allocation adjustments were not significant.

Included in the property, plant and equipment associated with the Transwestern acquisition is an aggregate plant acquisition adjustment of $446.2 million, which represents costs allocated to Transwestern's transmission plant. This amount has not been included in the determination of tariff rates Transwestern charges to its regulated customers. The unamortized balance of this adjustment was $419.6 million at December 31, 2008 and is being amortized over 35 years, the composite weighted average estimated remaining life of Transwestern's assets as of the acquisition date.

Regulatory assets, included in intangible and other assets on the consolidated balance sheet, established in the Transwestern purchase price allocation consist of the following:

Accumulated reserve adjustment	$ 42,132
AFUDC gross-up	9,280
Environmental reserves	6,623
South Georgia deferred tax receivable	2,593
Cash Balance Plan	9,329
Total Regulatory Assets acquired	$ 69,957

All of Transwestern's regulatory assets are considered probable of recovery in rates.

We recorded the following intangible assets and goodwill in conjunction with the fiscal year 2007 acquisitions described above:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Intangible assets:			
Contract rights and customer lists (6 to 15 years)	$ 23,015	$ 47,582	$ -
Financing costs (7 to 9 years)	-	13,410	-
Other	-	-	3,808
Total intangible assets	23,015	60,992	3,808
Goodwill	-	107,550	4,167
Total intangible assets and goodwill acquired	$ 23,015	$ 168,542	$ 7,975

Goodwill was warranted because these acquisitions enhance our current operations, and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible. We do not believe that the acquired intangible assets have any significant residual value at the end of their useful life.

4. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

ETP is party to an agreement with Kinder Morgan Energy Partners, L.P. ("KMP") for a 50/50 joint development of the Midcontinent Express pipeline. Construction of the approximately 500-mile pipeline was completed and natural gas transportation service commenced August 1, 2009 on the pipeline from Delhi, Louisiana, to an interconnect with the Transco interstate natural gas pipeline in Butler, Alabama. Interim service began on the pipeline from Bennington, Oklahoma, to Delhi in April 2009. In July 2008, Midcontinent Express Pipeline LLC ("MEP"), the entity formed to construct, own and operate this pipeline, completed an open season with respect to a capacity expansion of the pipeline from the current capacity of 1.4 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to an interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is expected to be completed in the latter part of 2010. This expansion was approved by the Federal Energy Regulatory Commission (the "FERC") in September 2009.

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

Fayetteville Express Pipeline LLC

ETP is party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC ("FEP"), the entity formed to construct, own and operate this pipeline, received FERC approval of its application for authority to construct and operate this pipeline. That order is currently subject to a limited request for rehearing. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. The pipeline project is expected to be in service by the end of 2010. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America ("NGPL") in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

Capital Contributions to Affiliates

During the year ended December 31, 2009, we contributed $664.5 million to MEP. FEP's capital expenditures are being funded under a credit facility. All of our contributions to FEP were reimbursed to us in 2009, including $9.0 million that we contributed in 2008.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, MEP and FEP (on a 100% basis):

	December 31, 2009	December 31, 2008
Current assets	$ 33,794	$ 9,953
Property, plant and equipment, net	2,576,031	1,012,006
Other assets	19,658	-
Total assets	$ 2,629,483	$ 1,021,959
Current liabilities	$ 105,951	$ 163,379
Non-current liabilities	1,198,882	840,580
Equity	1,324,650	18,000
Total liabilities and equity	$ 2,629,483	$ 1,021,959

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Revenue	$ 98,593	$ -	$ -	$ -
Operating income	47,818	-	-	-
Net income	36,555	1,057	-	-

As stated above, MEP was placed into service during 2009.

5. INCOME PER LIMITED PARTNER UNIT:

Basic net income per limited partner unit is computed by dividing net income, after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding. Diluted net income per limited partner unit is computed by dividing net income (as adjusted as discussed herein), after considering the General Partner's interest, by the weighted average number of limited partner interests outstanding and the number of unvested ETE Incentive Units granted. For the diluted earnings per share computation, income allocable to the limited partners is reduced, where applicable, for the decrease in earnings from ETE's limited partner unit ownership in ETP that would have resulted assuming the incremental units related to ETP's equity incentive plans had been issued during the respective periods. Such units have been determined based on the treasury stock method.

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Basic Net Income per Limited Partner Unit:				
Limited Partner's interest in net income	$ 441,103	$ 373,883	$ 92,390	$ 318,312
Weighted average limited partner units	222,898,203	222,829,956	222,829,916	204,578,719
Basic net income per limited partner unit	$ 1.98	$ 1.68	$ 0.41	$ 1.56
Diluted Net Income per Limited Partner Unit:				
Limited Partner's interest in net income	$ 441,103	$ 373,883	$ 92,390	$ 318,312
Dilutive effect of Unit Grants	(410)	(349)	(218)	(376)
Diluted net income available to limited partners	$ 440,693	$ 373,534	$ 92,172	$ 317,936
Weighted average limited partner units	222,898,203	222,829,956	222,829,916	204,578,719
Diluted net income per limited partner unit	$ 1.98	$ 1.68	$ 0.41	$ 1.55

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2009	December 31, 2008	
ETP Senior Notes:			
5.95% Senior Notes, due February 1, 2015	$ 750,000	$ 750,000	Payable upon maturity. Interest is paid semi-annually.
5.65% Senior Notes, due August 1, 2012	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.125% Senior Notes, due February 15, 2017	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.625% Senior Notes, due October 15, 2036	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.0% Senior Notes, due July 1, 2013	350,000	350,000	Payable upon maturity. Interest is paid semi-annually.
6.7% Senior Notes, due July 1, 2018	600,000	600,000	Payable upon maturity. Interest is paid semi-annually.
7.5% Senior Notes, due July 1, 2038	550,000	550,000	Payable upon maturity. Interest is paid semi-annually.
9.7% Senior Notes due March 15, 2019	600,000	600,000	Put option on March 15, 2012. Payable upon maturity. Interest is paid semi-annually.
8.5% Senior Notes due April 15, 2014	350,000	-	Payable upon maturity. Interest is paid semi-annually.
9.0% Senior Notes due April 15, 2019	650,000	-	Payable upon maturity. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Notes, due November 17, 2014	88,000	88,000	Payable upon maturity. Interest is paid semi-annually.
5.54% Senior Unsecured Notes, due November 17, 2016	125,000	125,000	Payable upon maturity. Interest is paid semi-annually.
5.64% Senior Unsecured Notes, due May 24, 2017	82,000	82,000	Payable upon maturity. Interest is paid semi-annually.
5.89% Senior Unsecured Notes, due May 24, 2022	150,000	150,000	Payable upon maturity. Interest is paid semi-annually.
6.16% Senior Unsecured Notes, due May 24, 2037	75,000	75,000	Payable upon maturity. Interest is paid semi-annually.
5.36% Senior Unsecured Notes, due December 9, 2020	175,000	-	Payable upon maturity. Interest is paid semi-annually.
5.66% Senior Unsecured Notes, due December 9, 2024	175,000	-	Payable upon maturity. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	24,000	36,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
Medium Term Note Program:			
7.17% Series A Senior Secured Notes	-	2,400	Matured in November 2009.
7.26% Series B Senior Secured Notes	6,000	8,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	4,571	9,142	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	5,750	11,500	Annual payments of $5,750 due each August 15 through 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	33,100	45,550	Annual payments of $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	6,000	7,000	Annual payments of $1,000 due each August 15 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.89% Series H Senior Secured Notes	5,091	5,818	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities and Term Loans:			
ETE Senior Secured Revolving Credit Facility	123,951	121,642	See terms below under “Parent Company Credit Facilities”.
ETE Senior Secured Term Loan	1,450,000	1,450,000	See terms below under “Parent Company Credit Facilities”.
ETP Revolving Credit Facility	150,000	902,000	See terms below under "ETP Credit Facility".
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	10,000	See terms below under "HOLP Credit Facility".
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 8.06% and 7.91% for December 31, 2009 and 2008, respectively	7,898	11,249	Due in installments through 2014.
Other	2,390	2,765	Due in installments through 2024.
Unamortized discounts	(12,829)	(13,477)	
	7,791,922	7,235,589	
Current maturities	(40,924)	(45,232)	
	$ 7,750,998	$ 7,190,357	

Future maturities of long-term debt for each of the next five years and thereafter are as follows:

2010	$ 40,924
2011	168,558
2012	2,022,881
2013	372,569
2014	443,519
Thereafter	4,743,471
	$ 7,791,922

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of ETP and the obligation of ETP to repay the ETP Senior Notes is not guaranteed by us, ETP or any of ETP's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours, ETP's or its subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of ETP's existing and future subsidiaries.

In April 2009, we completed a public offering of $350.0 million aggregate principal amount of 8.5% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.0% Senior Notes due 2019 (collectively the "2009 ETP Notes"). The offering of the 2009 ETP Notes closed on April 7, 2009 and we used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

Transwestern Senior Unsecured Notes

Transwestern's long-term debt consists of $213.0 million remaining principal amount of notes assumed in connection with the Transwestern acquisition, $307.0 million aggregate principal amount of notes issued in May 2007, and $350.0 million aggregate principal amount of notes issued in December 2009. The proceeds from the notes issued in December 2009 were used by Transwestern to repay amounts under an intercompany loan agreement. No principal payments are required under any of the Transwestern notes prior to their respective maturity dates. The Transwestern notes rank pari passu with Transwestern's other unsecured debt. The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. Interest is paid semi-annually.

Transwestern's debt agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the "HOLP Notes").

Revolving Credit Facilities

Parent Company Facilities

The Parent Company has a $1.45 billion Term Loan Facility and a Term Loan Maturity Date of November 1, 2012 (the "Parent Company Credit Agreement"). The Parent Company Credit Agreement also includes a $500.0 million Secured Revolving Credit Facility (the "Parent Company Revolving Credit Facility") available through February 8, 2011. The Parent Company Revolving Credit Facility includes a Swingline loan option with a maximum borrowing of $10.0 million and a daily rate based on LIBOR.

The total outstanding amount borrowed under the Parent Company Credit Agreement and the Parent Company Revolving Credit Facility as of December 31, 2009 was $1.57 billion. The total amount available under the Parent Company's debt facilities as of December 31, 2009 was $376.0 million. The Parent Company Revolving Credit Facility also contains an accordion feature, which will allow the Parent Company, subject to bank syndication's approval, to expand the facility's capacity up to an additional $100.0 million.

The maximum commitment fee payable on the unused portion of the Parent Company Revolving Credit Facility is based on the applicable Leverage Ratio, which is currently at Level III or 0.375%. Loans under the Parent Company Revolving Credit Facility bear interest at Parent Company's option at either (a) the Eurodollar rate plus the applicable margin or (b) base rate plus the applicable margin. The applicable margins are a function of the Parent Company's leverage ratio that corresponds to levels set forth in the agreement. The applicable Term Loan bears interest at (a) the Eurodollar rate plus 1.75% per annum and (b) with respect to any Base Rate Loan, at Prime Rate plus 0.25% per annum. As of December 31, 2009, the weighted average interest rate was 1.94% for the amounts outstanding on the Parent Company Senior Secured Revolving Credit Facility and the Parent Company $1.45 billion Senior Secured Term Loan Facility.

The Parent Company Credit Agreement is secured by a lien on all tangible and intangible assets of the Parent Company and its subsidiaries, including its ownership of 62,500,797 ETP Common Units, the Parent Company's 100% interest in ETP LLC and ETP GP with indirect recourse to ETP GP's General Partner interest in ETP and 100% of ETP GP's outstanding incentive distribution rights in ETP, which the Parent Company holds through its ownership of ETP GP.

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity, under the Amended and Restated Credit Agreement). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of December 31, 2009, there was a balance outstanding in the ETP Credit Facility of $150.0 million in revolving credit loans and approximately $62.2 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2009 was 0.78%. The total amount available under the ETP Credit Facility, as of December 31, 2009, which is reduced by any letters of credit, was approximately $1.79 billion. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility (total book value as of December 31, 2009 of approximately $1.2 billion). At December 31, 2009, there was $10.0 million outstanding in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of December 31, 2009 was $64.0 million.

Covenants Related to Our Credit Agreements

The agreements related to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions. The agreements and indentures related to each of the Parent Company Revolving Credit Facility and Senior Secured Term Loan Facility and ETP's and the Operating Companies' HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to the Parent Company, ETP and the Operating Companies, including the maintenance of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens as described in further detail below.

The Parent Company Revolving Credit Facility and Senior Secured Term Loan Facility contain financial covenants as follows:

- Maximum Leverage Ratio – Consolidated Funded Debt of the Parent Company (as defined) to Consolidated EBITDA (as defined in the agreements) of the Parent Company of not more than 4.50 to 1.00, with a permitted increase to 5.00 to 1.00 during a specified acquisition period extending for two fiscal quarters following the close of a specified acquisition

- Maximum Consolidated Leverage Ratio – Consolidated Funded Debt of the Parent Company and ETP to Consolidated EBITDA of ETP of not more than 5.50 to 1.00

- Interest Coverage Ratio may not be less than 3.00 to 1.00

- Value to Loan Ratio may not be less than 2.00 to 1.00

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries, ability to, among other things:

- incur indebtedness;

- grant liens;

- enter into mergers;

- dispose of assets;

- make certain investments;

- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);

- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;

- engage in transactions with affiliates;

- enter into restrictive agreements; and

- enter into speculative hedging contracts.

The credit agreement related to the ETP Credit Facility also contains a financial covenant that provides that on each date ETP makes a distribution, the leverage ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1, with a permitted increase to 5.5 to 1 during a specified acquisition period, as defined in the ETP Credit Facility. This financial covenant could therefore restrict ETP's ability to make cash distributions to its Unitholders, its general partner and the holder of its incentive distribution rights.

The agreements related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to HOLP, including the maintenance of various financial and leverage covenants and limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The financial covenants require HOLP to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not less than 2.25 to 1. These debt agreements also provide that HOLP may declare, make, or incur a liability to make restricted payments during each fiscal quarter, if: (a) the amount of such restricted payment, together with all other restricted payments during such quarter, do not exceed the amount of Available Cash (as defined in the agreements related to the HOLP Notes and HOLP Credit Facility) with respect to the immediately preceding quarter (which amount is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes during the last quarter and in addition, in the third, second and first quarters preceding a quarter in which a scheduled principal payment is to be made on the HOLP Notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates), (b) no default or event of default exists before such restricted payments, and (c) the amounts of HOLP's restricted payment is not disproportionately greater than the payment amount from ETC OLP utilized to fund payment obligations of ETP and its general partner with respect to ETP's Common Units.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities and the note agreements related to the HOLP Notes could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

We are required to assess compliance quarterly and were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2009.

7. PARTNERS' CAPITAL:

Limited Partner Units

Limited partner interests in the Partnership are represented by Common Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. The Partnership's Common Units are registered under the Securities Act of 1934 and are listed for trading on the New York Stock Exchange ("NYSE"). Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than the Partnership's General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

As of December 31, 2009, there were issued and outstanding 222,898,248 Common Units representing an aggregate 99.69% limited partner interest in the Partnership.

Our Partnership Agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. For any fiscal year that the Partnership has net profits, such net profits are first allocated to the General Partner until the aggregate amount of net profits for the current and all prior fiscal years equals the aggregate amount of net losses allocated to the General Partner for the current and all prior fiscal years. Second, such net profits shall be allocated to the Limited Partners pro rata in accordance with their respective sharing ratios. For any fiscal year in which the Partnership has net losses, such net losses shall be first allocated to the Limited Partners in proportion to their respective adjusted capital account balances, as defined by the Partnership Agreement, (before taking into account such net losses) until their adjusted capital account balances have been reduced to zero. Second, all remaining net losses shall be allocated to the General Partner. The General Partner may distribute to the Limited Partners funds of the Partnership that the General Partner reasonably determines are not needed for the payment of existing or foreseeable Partnership obligations and expenditures.

In connection with our initial public offering in February 2006, we issued Class B Units to our management, and all of the Class B Units were converted to ETE Common Units in March 2007. In November 2006, we issued Class C Units to acquire limited partner interest in ETP GP, and in February 2007, all of the Class C Units were converted to ETE Common Units.

Common Units

The change in Common Units is as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Number of Units, beginning of period	222,829,956	222,829,956	222,828,332	124,360,520
Issuance of restricted Common Units under long-term incentive plan	68,292	-	1,624	1,948
Issuance of Common Units	-	-	-	12,795,394
Conversion of Class B Units to Common Units	-	-	-	2,521,570
Conversion of Class C Units to Common Units	-	-	-	83,148,900
Number of Units, end of period	222,898,248	222,829,956	222,829,956	222,828,332

Sale of Common Units by Subsidiary

The Parent Company accounts for the difference between the carrying amount of its investment in ETP and the underlying book value arising from issuance of units by ETP (excluding unit issuances to the Parent Company) as a capital transaction. The capital transactions are reflected in the Partnership's consolidated balance sheets as an increase in partners' capital. If ETP issues units at a price less than the Parent Company's carrying value per unit, the Parent Company assesses whether the investment in ETP has been impaired, in which case a provision would be reflected in the statement of operations. The Parent Company did not recognize any impairment related to the issuance of ETP Common Units during the periods presented.

On November 1, 2006, the Parent Company purchased 26,086,957 Class G Units representing limited partnership interests in ETP. The price per unit paid for each of the Common Units was equal to $46.00 per unit, based upon a market discount from the NYSE closing price of the ETP's Common Units on October 31, 2006 of $48.94. ETP used a portion of the proceeds to purchase interests in CCEH (see Note 3). On May 1, 2007, the Unitholders of ETP approved the conversion of the Class G Units to Common Units and all the outstanding ETP Class G Units converted to ETP Common Units on a one-for-one basis on such date. The Parent Company recorded the premium of $451.2 million (the difference between the Parent Company's share of the underlying book value in ETP before and after the purchase of the Class G Units) as a reduction of the Parent Company's limited partners' capital with a corresponding increase in minority interest.

The following table summarizes ETP's public offerings of ETP Common Units:

Date	Number of Common Units (1)	Price per Unit	Net Proceeds	Use of Proceeds
December 2007 (2)	5,750,000	$ 48.81	$ 269.4	(3)
July 2008	8,912,500	39.45	337.5	(4)
January 2009	6,900,000	34.05	225.4	(4)
April 2009	9,775,000	37.55	352.4	(5)
October 2009	6,900,000	41.27	276.0	(4)
January 2010	9,775,000	44.72	423.6	(4)(5)

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.
(2) Amounts include the exercise of the overallotment option by the underwriters in January 2008.
(3) Proceeds were used to repay amounts outstanding under ETP's prior term loan facility.
(4) Proceeds were used to repay amounts outstanding under the ETP Credit Facility.
(5) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

On August 26, 2009, ETP entered into an Equity Distribution Agreement with UBS Securities LLC ("UBS"). Pursuant to this agreement, ETP may offer and sell from time to time through UBS, as their sales agent, ETP Common Units having an aggregate offering price of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between ETP and UBS. Under the terms of this agreement, ETP may also sell ETP Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of ETP Common Units to UBS as principal would be pursuant to the terms of a separate agreement between ETP and UBS. During 2009, ETP issued 2,079,593 ETP Common Units pursuant to this agreement 1,891,691 of which have been settled as of December 31, 2009. The proceeds of approximately $81.5 million, net of commissions, were used to repay amounts outstanding under the ETP Credit Facility.

As a result of ETP's issuance of ETP Common Units, we have recognized increases in partner's capital of $97.0 million and $48.8 million for the years ended December 31, 2009 and 2008, respectively, and $48.9 million for the four months ended December 31, 2007.

Contributions to Subsidiary

The Parent Company indirectly owns the entire general partner interest in ETP through its ownership of ETP GP, the general partner of ETP. In order to maintain its general partner interest in ETP, ETP GP has previously been required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP. ETP GP was required to contribute approximately $12.3 million and $8.0 million for the years ended December 31, 2009 and 2008, $5.0 million for the four months ended December 31, 2007, and $24.5 million for the year ended August 31, 2007, respectively. As of December 31, 2009, ETP GP has a contribution payable to ETP of $8.9 million.

In July 2009, ETP amended and restated its partnership agreement, and as a result, ETP GP is no longer required to make corresponding contributions to maintain its general partner interest in ETP.

Parent Company Quarterly Distributions of Available Cash

Our distribution policy is consistent with the terms of our Partnership Agreement, which requires that we distribute all of our available cash quarterly. We currently have no independent operations outside of our interests in ETP.

Our only cash-generating assets currently consist of distributions from ETP related to the following limited and general partner interests, including incentive distribution rights in ETP:

- ETE's ownership of the general partner interest in ETP, which it holds through its ownership interests in ETP GP.
- 62,500,797 ETP Common Units, which ETE holds directly, representing approximately 35% of the total outstanding ETP Common Units as of December 31, 2009, and
- 100% of the incentive distribution rights in ETP, which ETE holds through its ownership interests in ETP GP and which entitle it to receive specified percentages of the cash distributed by ETP as ETP's per unit distribution increases. The Parent Company's incentive distribution rights entitle it to receive incentive distributions to the extent that quarterly distributions to ETP's Unitholders exceed $0.275 per unit ($1.10 per unit on an annualized basis). These incentive distributions entitle the Parent Company to increasing percentages of ETP's cash distributions based upon exceeding incentive distribution thresholds specified in ETP's Partnership Agreement, which incentive distribution rights entitle the Parent Company to receive 48% of ETP's cash distributions in excess of $0.4125 per unit. At ETP's current distribution levels, the Parent Company is entitled to receive cash distributions at the highest incentive distribution level of 48% with respect to ETP's distributions in excess of $0.4125 per unit.

Our distributions declared during the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007 are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2009	November 9, 2009	November 19, 2009	$ 0.5350
	August 7, 2009	August 19, 2009	0.5350
	May 8, 2009	May 19, 2009	0.5250
	February 6, 2009	February 19, 2009	0.5100
Calendar Year Ended December 31, 2008	November 10, 2008	November 19, 2008	$ 0.4800
	August 7, 2008	August 19, 2008	0.4800
	May 5, 2008	May 19, 2008	0.4400
	February 1, 2008 (1)	February 19, 2008	0.5500
Transition Period Ended December 31, 2007	October 5, 2007	October 19, 2007	$ 0.3900
Fiscal Year Ended August 31, 2007	July 2, 2007	July 19, 2007	$ 0.3725
	April 9, 2007	April 16, 2007	0.3560
	January 4, 2007	January 19, 2007	0.3400
	October 5, 2006	October 19, 2006	0.3125

(1) One-time four month distribution – On January 18, 2008, our Board of Directors approved the management recommendation for a one-time four-month distribution for our Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETE's distribution amount related to the four months ended December 31, 2007 was $0.55 per Common Unit, representing a distribution of $0.41 per unit for the three-month period and $0.14 per unit for the additional month.

The total amount of distributions we have declared is as follows (all from Available Cash from our operating surplus and are shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 475,911	$ 425,640	$ 122,556	$ 294,175
Class B Units	-	-	-	857
Class C Units	-	-	-	28,261
General Partner	1,478	1,322	381	1,009
Total distributions declared	$ 477,389	$ 426,962	$ 122,937	$ 324,302

On January 28, 2010, the Parent Company declared a cash distribution for the fourth quarter ended December 31, 2009 of $0.54 per Common Unit, or $2.16 annualized. We paid this distribution on February 19, 2010 to Unitholders of record at the close of business on February 8, 2010.

ETP's Quarterly Distribution of Available Cash

ETP's Partnership Agreement requires that ETP distribute all of its Available Cash to its Unitholders and its General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any fiscal quarter of ETP, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by its General Partner in its sole discretion to provide for the proper conduct of ETP's business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in ETP's Partnership Agreement.

ETP's distributions declared during the periods presented below are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2009	November 9, 2009	November 16, 2009	$ 0.89375
	August 7, 2009	August 14, 2009	0.89375
	May 8, 2009	May 15, 2009	0.89375
	February 6, 2009	February 13, 2009	0.89375
Calendar Year Ended December 31, 2008	November 10, 2008	November 14, 2008	$ 0.89375
	August 7, 2008	August 14, 2008	0.89375
	May 5, 2008	May 15, 2008	0.86875
	February 1, 2008 (1)	February 14, 2008	1.12500
Transition Period Ended December 31, 2007	October 5, 2007	October 15, 2007	$ 0.82500
Fiscal Year Ended August 31, 2007	July 2, 2007	July 16, 2007	$ 0.80625
	April 6, 2007	April 13, 2007	0.78750
	January 4, 2007	January 15, 2007	0.76875
	October 5, 2006	October 16, 2006	0.75000

(1) One-time four month distribution – On January 18, 2008 ETP's Board of Directors approved the management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP's distribution amount related to the four months ended December 31, 2007 was $1.125 per Common Unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month.

The total amount of distributions the Parent Company received from ETP relating to its limited partner interests, general partner interests and incentive distribution rights of ETP are as follows (shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners Interests	$ 223,440	$ 221,878	$ 70,313	$ 199,221
General Partner Interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
Total distributions received from ETP	$ 593,431	$ 537,775	$ 161,198	$ 435,279

The total amounts of ETP distributions declared during the periods presented in the consolidated financial statements are as follows (all from Available Cash from ETP's operating surplus and are shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 629,263	$ 537,731	$ 160,672	$ 396,095
Class E Units	12,484	12,484	3,121	12,484
Class G Units	-	-	-	40,598
General Partner Interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$ 1,011,738	$ 866,112	$ 254,678	$ 685,235

Upon their conversion to ETP Common Units, all the ETP Class G Units ceased to have the right to participate in ETP distributions of available cash from operating surplus as itemized above.

On January 28, 2010, ETP declared a cash distribution for the fourth quarter ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized. ETP paid this distribution on February 15, 2010 to Unitholders of record at the close of business on February 8, 2010.

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31, 2009	December 31, 2008
Net gain on commodity related hedges	$ 1,991	$ 8,735
Net loss on interest rate hedges	(56,210)	(68,896)
Unrealized gains (losses) on available-for-sale securities	4,941	(5,983)
Noncontrolling interest	(4,350)	(1,681)
Total AOCI, net of tax	$ (53,628)	$ (67,825)

8. UNIT-BASED COMPENSATION PLANS:

We recognized non-cash unit-based compensation expense related to the unit-based compensation plans of ETP and ETE of $24.6 million and $24.3 million for the years ended December 31, 2009 and 2008, $8.1 million for the four months ended December 31, 2007, and $10.5 million for the year ended August 31, 2007, respectively.

ETE Long-Term Incentive Plan

Concurrently with the IPO during the second quarter of fiscal year 2006, 2,521,570 Class B Units were issued to McReynolds Equity Partners, L.P., the general partner of which is owned and controlled by John W. McReynolds. On March 27, 2007, the Class B Units were converted to Common Units.

In addition, the Board of Directors or the Compensation Committee of the board of directors of the Partnership's general partner (the "Compensation Committee") may from time to time grant additional awards to employees, directors and consultants of ETE's general partner and its affiliates who perform services for ETE. The plan provides for the following five types of awards: restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The number of additional units that may be delivered pursuant to these awards is limited to 3,000,000 units, excluding the Class B Units discussed above. As of December 31, 2009, 2,887,136 units remain available to be awarded under the plan.

During 2009 and 2008, the Compensation Committee granted a total of 41,000 and 65,000 ETE units with grant date fair values of $16.64 and $30.76 per unit, respectively, to employees with vesting over a five-year period at 20% per year. These awards include rights to distributions paid on unvested units.

On December 22, 2006, the Compensation Committee voted to award each ETE Director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, ETP, or a subsidiary ("Director Participant"), who is then in office and, automatically on the first day of the fiscal year thereafter, an award of Units equal to $15 thousand divided by the fair market value of ETE Common Units on such date ("Annual Director's Grant"). Each award to a Director Participant will vest at the rate of one third per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, all awards to a Director Participant shall become fully vested upon a change in control, as defined by the 2004 Unit Plan. During 2009, a total of 14,192 ETE units vested, with a total fair value of $0.4 million. As of December 31, 2009, a total of 96,836 restricted units granted to ETE employees and directors remain outstanding, for which we expect to recognize a total of $1.9 million in compensation over a weighted average period of 2.7 years.

ETP Unit-Based Compensation Plans

ETP has issued equity awards to employees and directors under the following plans:

- ***2008 Long-Term Incentive Plan***. On December 16, 2008, ETP Unitholders approved the ETP 2008 Long-Term Incentive Plan (the "ETP 2008 Incentive Plan"), which provides for awards of options to purchase ETP Common Units, awards of restricted units, awards of phantom units, awards of Common Units, awards of distribution equivalent rights ("DERs"), awards of Common Unit appreciation rights, and other unit-based awards to employees of ETP, ETP GP, ETP LLC, a subsidiary or their affiliates, and members of ETP LLC's board of directors, which we refer to as the board of directors. Up to 5,000,000 ETP Common Units may be granted as awards under the ETP 2008 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the ETP 2008 Incentive Plan. The ETP 2008 Incentive Plan is effective until December 16, 2018 or, if earlier, the time which all available units under the ETP 2008 Incentive Plan have been issued to participants or the time of termination of the plan by the board of directors. As of December 31, 2009, a total of 4,213,111 ETP Common Units remain available to be awarded under the ETP 2008 Incentive Plan.

- ***2004 Unit Plan***. ETP's Amended and Restated 2004 Unit Award Plan (the "ETP 2004 Unit Plan") provides for awards of up to 1,800,000 ETP Common Units and other rights to its employees, officers and directors. Any awards that are forfeited or which expire for any reason or any units, which are not used in the settlement of an award, will be available for grant under the ETP 2004 Unit Plan. As of December 31, 2009, 5,578 ETP Common Units were available for future grants under the ETP 2004 Unit Plan.

ETP Employee Grants

Prior to December 2007, substantially all of the awards granted to employees required the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three-year period with 100% of such one-third vesting if the total return for the ETP units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the Compensation Committee, 65% of such one-third vesting if the total return of the ETP units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of the ETP units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of the ETP units for the year plus the aggregate per unit cash distributions received for the year. Non-cash compensation expense is recorded for these ETP awards based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded.

In October 2008, the Compensation Committee determined that, of the unit awards subject to the achievement of performance objectives, 25% of the ETP Common Units subject to such awards eligible to vest on September 1, 2007 became vested and 75% of the awards were forfeited based on ETP's performance for the twelve-month period ended August 31, 2008. In October 2008, the Compensation Committee approved a special grant of the new unit awards that entitled each holder to receive a number of ETP Common Units equal to the number of ETP Common Units forfeited as of September 1, 2007, which new unit awards became fully vested on October 15, 2008. These Compensation Committee actions affected all ETP employee unit awards including unit awards granted to ETP's executive officers.

Commencing in December 2007, ETP has also granted restricted unit awards to employees that vest over a specified time period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. Upon vesting, ETP Common Units are issued. The unit awards under ETP's equity incentive plans generally require the continued employment of the recipient during the vesting period; however, the Compensation Committee has complete discretion to accelerate the vesting of unvested unit awards.

In 2008 and 2009, the Compensation Committee approved the grant of new unit awards, which vest over a five-year period at 20% per year, subject to continued employment through each specified vesting date. These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. We refer to these rights as "distribution equivalent rights."

Prior to 2008 and 2009, units were generally awarded without distribution equivalent rights. For such awards, ETP calculated the grant-date fair value based on the market value of the underlying units, reduced by the present value of the distributions expected to be paid on the units during the requisite service period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the distribution yield at that time.

Director Grants

Under ETP's equity incentive plans, ETP's non-employee directors each receive unvested ETP Common Units with a grant-date fair value of $50,000 each year. These non-employee director grants vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

Award Activity

The following table shows the activity of the ETP awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2008	1,372,568	$ 36.83
Awards granted	763,190	43.56
Awards vested	(336,386)	36.02
Awards forfeited	(108,780)	39.17
Unvested awards as of December 31, 2009	1,690,592	39.88

The balance above for unvested awards as of December 31, 2008 includes 150,852 unit awards with a grant-date fair value of $43.96 per unit, which were granted prior to 2008 and were subject to a performance condition, as described above. These remaining performance awards vested in 2009, and none of the unvested unit awards outstanding as of December 31, 2009 contain performance conditions.

During the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, the weighted average grant-date fair value per unit award granted was $43.56, $33.86, $42.46 and $43.73, respectively. The total fair value of awards vested was $14.7 million, $14.6 million, $3.3 million and $7.9 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2009, a total of 1,690,592 unit awards remain unvested, for which ETP expects to recognize a total of $50.9 million in compensation expense over a weighted average period of 1.9 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by an ETE officer, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officer. These rights include the economic benefits of ownership of these ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE.

During the years ended December 31, 2008 and August 31, 2007, unvested rights related to 450,000 ETE common units and 675,000 ETE common units, respectively, with aggregate grant-date fair values of $10.3 million and $23.5 million, respectively, were awarded to ETP officers. During the year ended December 31, 2008, unvested rights related to 240,000 ETE common units were forfeited. During the years ended December 31, 2009 and 2008 and the four months ended December 31, 2007, ETP officers vested in rights related to 165,000 ETE common units, 135,000 ETE common units, and 55,000 ETE common units, respectively, with aggregate fair values upon vesting of $4.6 million, $3.5 million, and $1.9 million, respectively.

ETP is recognizing non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded the ETP employees assuming no forfeitures. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, ETP recognized non-cash compensation expense, net of forfeitures, of $6.4 million, $3.5 million, $3.6 million, and $5.2 million, respectively, as a result of these awards.

As of December 31, 2009, rights related to 530,000 ETE common units remain outstanding, for which we expect to recognize a total of $6.8 million in compensation expense over a weighted average period of 1.9 years

9. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Current provision:				
Federal	$ (8,850)	$ (180)	$ 2,990	$ 7,896
State	9,657	12,241	5,831	10,432
Total	807	12,061	8,821	18,328
Deferred provision:				
Federal	8,643	(8,531)	516	(7,494)
State	(221)	278	612	557
Total	8,422	(8,253)	1,128	(6,937)
Total tax provision	$ 9,229	$ 3,808	$ 9,949	$ 11,391

On May 18, 2006, the State of Texas enacted House Bill 3, which replaced the existing state franchise tax with a “margin tax”. In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin, which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law’s effective date of January 1, 2007. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $8.5 million, $10.5 million, $3.9 million and $6.9 million, respectively.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. The difference between the statutory rate and the effective rate is summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate net of federal benefit	1.08%	1.59%	2.57%	1.25%
Earnings not subject to tax at the Partnership level	(34.77%)	(36.03%)	(32.41%)	(34.23%)
Effective tax rate	1.31%	0.56%	5.16%	2.02%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the deferred tax liability were as follows:

	December 31, 2009	December 31, 2008
Property, plant and equipment	$ 204,083	$ 199,306
Other, net	(863)	(3,846)
Total deferred tax liability	203,220	195,460
Less current deferred tax asset (liability)	1,153	(589)
Total long-term deferred tax liability	$ 204,373	$ 194,871

10. MAJOR CUSTOMERS AND SUPPLIERS:

Our major customers are in the natural gas operations segments. Our natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while our NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively. Management believes that our portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer accounted for 10% or more of our consolidated revenue.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Propane segments				
Unaffiliated:				
M.P. Oils, Ltd.	15.1%	14.9%	14.2%	20.7%
Targa Liquids	14.3%	15.0%	15.9%	22.6%
Affiliated:				
Enterprise	50.3%	50.7%	50.6%	22.1%

Enterprise GP Holdings, L.P. and its subsidiaries ("Enterprise" or "EPE") became related parties on May 7, 2007, as discussed in Note 14. Titan purchases the majority of its propane from Enterprise pursuant to an agreement that expires in March 2010 and contains renewal and extension options.

We sold our investment in M-P Energy in October 2007. In connection with the sale, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

This concentration of suppliers may impact our overall operations either positively or negatively. However, management believes that the diversification of suppliers is sufficient to enable us to purchase all of our supply needs at market prices without a material disruption of operations if supplies are interrupted from any of our existing sources. Although no assurances can be given that supplies of natural gas, propane and NGLs will be readily available in the future, we expect a sufficient supply to continue to be available.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline. Approval from the FERC is still pending.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act ("NGA") proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern's tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern's existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern's existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity ("Order"). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service effective March 2009.

Guarantees

MEP Guarantee

ETP has guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the "MEP Facility"), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP's guarantee may be proportionately increased or decreased if its ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP's ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

The commitment amount under the MEP Facility was originally $1.4 billion. In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by ETP or KMP. In October 2009, the members made additional capital contributions to MEP, which MEP used to further reduce the outstanding borrowings under the MEP Facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275.0 million.

As of December 31, 2009, MEP had $29.5 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. ETP's contingent obligations with respect to its 50% guarantee of MEP's outstanding borrowings and letters of credit were $14.7 million and $16.6 million, respectively, as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.3%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the "FEP Facility"). ETP has guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP's guarantee may be proportionately increased or decreased if ETP's ownership percentage increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of December 31, 2009, FEP had $355.0 million of outstanding borrowings issued under the FEP Facility. ETP's contingent obligation with respect to its 50% guarantee of FEP's outstanding borrowings was $177.5 million as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $19.8 million, $17.2 million, $9.4 million and $33.2 million for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, respectively.

Future minimum lease commitments for such leases are:

2010	$	27,216
2011		24,786
2012		22,522
2013		20,385
2014		17,907
Thereafter		214,088

We have forward commodity contracts, which are expected to be settled by physical delivery. Short-term contracts, which expire in less than one year require delivery of up to 390,564 MMBtu/d. Long-term contracts require delivery of up to 125,551 MMBtu/d and extend through May 2014.

During fiscal year 2007, we entered into a long-term agreement with CenterPoint Energy Resources Corp ("CenterPoint") to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of the agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel storage facility.

We have a transportation agreement with TXU Portfolio Management Company, LP ("TXU Shipper") to transport a minimum of 100,000 MMBtu per year through 2012. We also have two natural gas storage agreements with TXU Shipper to store gas at two natural gas facilities that are part of the ET Fuel System that expire in 2012. As of December 31, 2009 and 2008 and August 31, 2007, respectively, the Partnership was entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month periods ended each May 31st. As a result, the Partnership recognized approximately $11.7 million, $10.7 million and $10.8 million in additional fees during the second quarter of 2008 and the third fiscal quarter of 2007, respectively.

We have signed long-term agreements with several parties committing firm transportation volumes into the East Texas pipeline. Those commitments include an agreement with XTO Energy Inc. ("XTO") to deliver approximately 200,000 MMBtu/d of natural gas into the pipeline that expires in June 2012. Exxon Mobil Corporation ("ExxonMobil") and XTO announced an agreement whereby ExxonMobil will acquire XTO. The pending acquisition, expected to be completed in the second quarter of 2010, is not expected to result in any changes to these commitments.

We also have two long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts require an aggregated capacity of approximately 238,000 MMBtu/d of natural gas and extend through 2011.

Titan has a purchase contract with Enterprise (see Note 14) to purchase the majority of Titan's propane requirements. The contract continues until March 2010 and contains renewal and extension options. The contract contains various service level agreements between the parties.

In connection with the sale of ETP's investment in M-P Energy in October 2007, ETP executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

We have commitments to make capital contributions to our joint ventures, for which we expect to make capital contributions of between $90 million and $105 million during 2010.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverages and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

FERC/CFTC and Related Matters. On July 26, 2007, the FERC issued to ETP an Order to Show Cause and Notice of Proposed Penalties (the "Order and Notice") that contains allegations that ETP violated FERC rules and regulations. The FERC alleged that ETP engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from ETP's commodities derivatives positions and from certain of ETP's index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods ETP violated the FERC's then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the Natural Gas Act ("NGA"). The FERC alleges that ETP violated this rule by artificially suppressing prices that were included in the Platts Inside FERC Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. In its Order and Notice, the FERC also alleged that ETP manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. The FERC specified that it was also seeking to revoke, for a period of 12 months, ETP's blanket marketing authority for sales of natural gas in interstate commerce at market-based prices. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP's trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, ETP entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against ETP and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement settles all outstanding FERC claims against ETP and provides that ETP make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims against ETP, including existing litigation claims as well as any new claims that may be asserted against this fund. Administrative law judge appointed by the FERC will determine the validity of any third party claim against this fund. Any party who receives money from this fund will be required to waive all claims against ETP related to this matter. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by exceeding the settlement agreement, ETP does not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with ETP's alleged conduct related to the FERC claims. The settlement agreement also requires ETP to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

We made the $5.0 million payment and established the $25.0 million fund in October 2009. The allocation of the $25.0 million fund is expected to be determined in 2010.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETP alleging damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETP for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETP contains an additional allegation that we and ETP transported gas in a manner that favored our affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have moved to compel arbitration and/or contested subject-matter jurisdiction in some of these cases. In one of these cases, the Texas Supreme Court ruled on July 3, 2009 that the state district court erred in ruling that a plaintiff was entitled to pre-arbitration discovery and therefore remanded to the state district court with a direction to rule on our original motion to compel arbitration pursuant to the terms of the arbitration clause in a natural gas contract between us and the plaintiff. This plaintiff has filed a motion with the Texas Supreme Court requesting a rehearing of the ruling.

ETP has also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. ETP filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. This action is currently on appeal before the First Court of Appeals, Houston, Texas.

A consolidated class action complaint has been filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, ETP had the market power to manipulate index prices, and that ETP used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit ETP's natural gas physical and financial trading positions, and that ETP intentionally submitted price and volume trade information to trade publications. This complaint also alleges that ETP violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by ETP manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, ETP filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, ETP filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 28, 2009, these decisions were appealed by the plaintiffs to the United States Court of Appeals for the 5th Circuit.

On March 17, 2008, a second class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period ETP exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit ETP's own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, ETP filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert a claim for common law fraud and attached a proposed amended complaint as an exhibit. ETP opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted ETP's motion to dismiss the complaint. On September 10, 2009, this decision was appealed by the plaintiff to the United States Court of Appeals for the 5th Circuit.

ETP is expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. ETP records accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. While ETP expects the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, ETP may not be able to realize such tax benefits. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount ETP becomes obliged to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, ETP will review the amount of their accrual related to these matters as developments related to these matters occur and ETP will adjust their accrual if ETP determines that it is probable that the amount ETP may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of ETP's accrual for these matters. As ETP's accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce ETP's cash available to service ETP's indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, ETP may experience a material adverse impact on its results of operations and its liquidity.

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariff, which were filed with and approved by the FERC. As a result, Transwestern believes that is has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. A hearing was held on April 24, 2007 regarding Transwestern's Supplemental Brief for Attorneys' fees, which was filed on January 8, 2007, and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg's opening brief was filed on or about July 31, 2007. Appellee's opposition brief was filed on or about November 21, 2007. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg's reply brief was filed in June 2008 and the hearing on all briefs was held in September 2008. On March 17, 2009, the Tenth Circuit affirmed the District Court's dismissal. Appellant sought appellate rehearing on the matter and the petition for rehearing was denied on May 4, 2009. A petition for writ of certiorari was filed by the Appellant on August 3, 2009, and the Supreme Court denied the petition for writ of certiorari on October 5, 2009. We do not believe the outcome of this case will have a material adverse effect on our financial position, results of operations or cash flows.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were engaged in ongoing litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the ("Cushion Gas Litigation"). Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. AEP is appealing the court decision. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of December 31, 2009 and 2008, accruals of approximately $11.1 million and $8.5 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of December 31, 2008, an accrual of $21.0 million was recorded as accrued and other current liabilities and other non-current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters, and we did not have any such accruals as of December 31, 2009.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.6 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the EPA’s Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the “EPA”) regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to HOLP, it is believed that HOLP’s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2009 or our December 31, 2008 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of December 31, 2009 and 2008, accruals on an undiscounted basis of $12.6 million and $13.3 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for all of the above environmental matters is adequate to cover the potential exposure for clean-up costs.

ETP’s pipeline operations are subject to regulation by the U.S. Department of Transportation (“DOT”) under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as (“high consequence areas”). Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing, or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause ETP to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

See Note 2 for further discussion of our accounting for derivative instruments and hedging activities.

Commodity Price Risk

The following table details the outstanding commodity-related derivatives:

		December 31, 2009		December 31, 2008	
	Commodity	Notional Volume MMBtu	Maturity	Notional Volume MMBtu	Maturity
Mark to Market Derivatives					
Basis Swaps IFERC/NYMEX	Gas	72,325,000	2010-2011	15,720,000	2009-2011
Swing Swaps IFERC	Gas	(38,935,000)	2010	(58,045,000)	2009
Fixed Swaps/Futures	Gas	4,852,500	2010-2011	(20,880,000)	2009-2010
Options - Puts	Gas	2,640,000	2010	-	N/A
Options - Calls	Gas	(2,640,000)	2010	-	N/A
Forwards/Swaps - in Gallons	Propane	6,090,000	2010	47,313,002	2009
Fair Value Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(22,625,000)	2010	-	N/A
Fixed Swaps/Futures	Gas	(27,300,000)	2010	-	N/A
Hedged Item - Inventory	Gas	27,300,000	2010	-	N/A
Cash Flow Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(13,225,000)	2010	(9,085,000)	2009
Fixed Swaps/Futures	Gas	(22,800,000)	2010	(9,085,000)	2009
Forwards/Swaps - in Gallons	Propane/Ethane	20,538,000	2010	-	N/A

We expect gains of $2.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the consolidated statements of operations on a net basis. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the year ended December 31, 2008, net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007 and net gains of approximately $2.2 million for the fiscal year ended August 31, 2007. There were no gains or losses associated with trading activities during the year ended December 31, 2009.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps. We have the following interest rate swaps outstanding as of December 31, 2009:

- Interest rate swaps with a notional amount of $300.0 million to pay an average fixed rate of 5.20% and receive a floating rate based on LIBOR. These swaps settle in May 2016;

- Interest rate swaps with a notional amount of $500.0 million to pay a fixed rate of 4.57% and receive a floating rate based on LIBOR. These swaps settle in November 2012 with a cancellable option in November 2010; and,

- Interest rate swaps with a notional amount of $700.0 million to pay an average fixed rate of 4.84% and receive a floating rate based on LIBOR. These swaps settle in November 2012.

In January 2010, we entered into interest rate swaps with notional amounts of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate that mature in July 2013 and February 2015, respectively. These swaps hedge against changes in the fair value of our fixed rate debt.

Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2009 and December 31, 2008:

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Derivatives designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 669	$ 10,665	$ (24,035)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	8,443	918	(201)	(119)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	-	-	(61,879)	(71,042)
Total derivatives designated as hedging instruments		$ 9,112	$ 11,583	$ (86,115)	$ (72,665)
Derivatives not designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 72,851	$ 432,614	$ (36,950)	$ (335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	3,928	17,244	(241)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	-	-	(76,157)	(149,765)
Total derivatives not designated as hedging instruments		$ 76,779	$ 449,858	$ (113,348)	$ (541,404)
Total derivatives		$ 85,891	$ 461,441	$ (199,463)	$ (614,069)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets. The Partnership had net deposits with counterparties of $79.7 million and $78.2 million as of December 31, 2009 and December 31, 2008, respectively.

The following tables detail the effect of the Partnership's derivative assets and liabilities in the consolidated statements of operations for the periods presented:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 3,143	$ 17,461	$ 21,406	$ 181,765
Interest Rate Swap Derivatives	Interest Expense	(14,705)	(57,676)	(23,846)	(578)
Total		$ (11,562)	$ (40,215)	$ (2,440)	$ 181,187

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 9,924	$ 42,874	$ 8,673	$ 162,340
Interest Rate Swap Derivatives	Interest Expense	(26,882)	(11,339)	650	3,879
Total		$ (16,958)	$ 31,535	$ 9,323	$ 166,219

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ -	$ (8,347)	$ 8,472	$ 183
Interest Rate Swap Derivatives	Interest Expense	-	-	(2)	(1,813)
Total		$ -	$ (8,347)	$ 8,470	$ (1,630)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
Derivatives in fair value hedging relationships:		2009	2008	2007	2007
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ 60,045	$ -	$ -	$ -
Total		$ 60,045	$ -	$ -	$ -

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
Derivatives not designated as hedging instruments:		2009	2008	2007	2007
Commodity Derivatives	Cost of Products Sold	$ 99,807	$ 12,478	$ 9,886	$ 30,028
Trading Commodity Derivatives	Revenue	-	(28,283)	(2,298)	5,228
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	33,619	(128,423)	(28,683)	29,081
Total		$ 133,426	$ (144,228)	$ (21,095)	$ 64,337

We recognized an $18.6 million unrealized loss, a $35.5 million unrealized gain, a $13.2 million unrealized gain and an $8.5 million unrealized loss on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships and amounts classified as trading activity) for the years ended December 31, 2009 and 2008, four months ended December 31, 2007 and the year August 31, 2007, respectively. In addition, for the year ended December 31, 2009, we recognized unrealized gains of $48.6 million on commodity derivatives and related hedged inventory accounted for as fair value hedges. There were no unrealized gains or losses on fair value hedging commodity derivatives in the prior years since we commenced fair hedge accounting on our storage inventory in April 2009.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

13. RETIREMENT BENEFITS:

ETP sponsors a 401(k) savings plan, which covers virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. Prior to 2009, employer-matching contributions were discretionary. We made matching contributions of $9.8 million, $9.7 million, $2.6 million and $8.5 million to the 401(k) savings plan for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively.

14. RELATED PARTY TRANSACTIONS:

On May 7, 2007, Ray Davis, previously the Co-Chairman of ETE and Co-Chairman and Co-Chief Executive Officer of ETP (retired August 15, 2007), and Natural Gas Partners VI, L.P. ("NGP") and affiliates of each, sold approximately 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise. In addition to the purchase of ETE Common Units, Enterprise acquired a non-controlling equity interest in our General Partner, LE GP, LLC ("LE GP"). Cash consideration paid by Enterprise totaled approximately $1.65 billion, reflecting a purchase price of $42.00 per ETE Common Unit. As a result of these transactions, EPE and its subsidiaries are considered related parties for financial reporting purposes.

On December 23, 2009, Dan L. Duncan and Ralph S. Cunningham were appointed as directors of our general partner. Mr. Duncan is Chairman and a director of EPE Holdings, LLC, the general partner of Enterprise; Chairman and a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., or EPD; and Group Co-Chairman of EPCO, Inc. TEPPCO Partners, L.P., or TEPPCO, is also an affiliate of EPE. Dr. Cunningham is the President and Chief Executive Officer of EPE Holdings, LLC, the general partner of Enterprise. These entities and other affiliates of Enterprise are referred to herein collectively as the "Enterprise Entities." Mr. Duncan directly or indirectly beneficially owns various interests in the Enterprise Entities, including various general partner interests and approximately 77.1% of the common units of Enterprise, and approximately 34% of the common units of EPD. On October 26, 2009, TEPPCO became a wholly owned subsidiary of Enterprise.

Our propane operations routinely enter into purchases and sales of propane with certain of the Enterprise Entities, including purchases under a long-term contract of Titan to purchase the majority of its propane requirements through certain of the Enterprise Entities. This agreement was in effect prior to our acquisition of Titan in 2006 and expires in March 2010 and contains renewal and extension options.

From time to time, our natural gas operations purchase from, and sell to, the Enterprise Entities natural gas and NGLs, in the ordinary course of business. We have a monthly natural gas storage contract with TEPPCO. Our natural gas operations and the Enterprise Entities transport natural gas on each other's pipelines and share operating expenses on jointly-owned pipelines.

The following table presents sales to and purchases from affiliates of Enterprise. Amounts reflected below for the year ended August 31, 2007 include transactions beginning on May 7, 2007, the date Enterprise became an affiliate. Volumes are presented in thousands of gallons for propane and NGLs and in billions of Btus for natural gas.

		Years Ended December 31,				Four Months Ended December 31,		Year Ended August 31,	
		2009		2008		2007		2007	
	Product	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars
Propane Operations:									
Sales	Propane	20,370	$ 14,046	13,230	$ 19,769	2,982	$ 4,619	1,470	$ 1,725
	Derivatives	-	5,915	-	2,442	-	1,857	-	22
Purchases	Propane	307,525	$ 305,148	318,982	$ 472,816	125,141	$ 192,580	61,660	$ 74,688
	Derivatives	-	38,392	-	20,993	-	-	-	1
Natural Gas Operations:									
Sales	NGLs	477,908	$ 374,020	58,361	$ 96,974	3,240	$ 4,726	464	$ 648
	Natural Gas	11,532	44,212	6,256	52,205	2,036	11,452	1,495	9,768
	Fees	-	(3,899)	-	5,093	-	610	-	-
Purchases	Natural Gas Imbalances	176	$ 1,164	3,488	$ (6,485)	313	$ (911)	3,120	$ 22,677
	Natural Gas	10,561	49,559	13,457	120,837	3,577	23,341	1,541	7,501
	Fees	-	(2,195)	-	876	-	311	-	-

As of December 31, 2009 and 2008, Titan had forward mark-to-market derivatives for approximately 6.1 million and 45.2 million gallons of propane at a fair value asset of $3.3 million and a fair value liability of $40.1 million, respectively, with Enterprise. In addition, as of December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 20.5 million gallons of propane at a fair value asset of $8.4 million with Enterprise.

The following table summarizes the related party balances with Enterprise on our consolidated balance sheets:

	December 31, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 47,005	$ 11,558
Accounts payable	3,518	567
Imbalance payable	694	(547)
Propane Operations:		
Accounts receivable	$ 3,386	$ 111
Accounts payable	31,642	33,308

Accounts receivable from related companies excluding Enterprise consist of the following:

	December 31, 2009	December 31, 2008
MEP	$ 632	$ 2,805
Energy Transfer Technologies, Ltd.	-	16
McReynolds Energy	-	202
Others	871	450
Total accounts receivable from related companies excluding Enterprise	$ 1,503	$ 3,473

Effective August 17, 2009, we acquired 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of the General Partner of ETP's general partner and the other of which is controlled by a member of ETP's management. In exchange, the former members acquired the right to receive (in cash or Common Units) future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG may receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

Prior to our acquisition of ETG in August 2009, our natural gas midstream and intrastate transportation and storage operations secured compression services from ETT. The terms of each arrangement to provide compression services were, in the opinion of independent directors of the General Partner, no more or less favorable than those available from other providers of compression services. During the years ended December 31, 2009 (through the ETG acquisition date) and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, we made payments totaling $3.4 million, $9.4 million, $0.8 million, and $2.4 million, respectively, to ETG for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations.

The Partnership pays ETP an annual administrative fee of $0.5 million for the provision of various general and administrative services for ETE's benefit.

The Chief Executive Officer ("CEO") of ETP's General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. We recorded non-cash compensation expense and an offsetting capital contribution of $1.3 million ($0.5 million in salary and $0.8 million in accrued bonuses) for each of the years ended December 31, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

15. REPORTABLE SEGMENTS:

Our financial statements reflect four reportable segments, which conduct their business exclusively in the United States of America, as follows:

- natural gas operations:
  - intrastate transportation and storage
  - interstate transportation
  - midstream
- retail propane and other retail propane related operations

Segments below the quantitative thresholds are classified as "other". The components of the "other" classification have not met any of the quantitative thresholds for determining reportable segments. Management has included the wholesale propane and natural gas compression services operations in "other" for all periods presented in this report because such operations are not material.

Midstream and intrastate transportation and storage segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

The volumes and results of operations data for fiscal year 2007 do not include the interstate operations for periods prior to Transwestern's acquisition on December 1, 2006.

See "Business Operations" in Note 1 for a description of the operations of each of our reportable segments.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general and administrative expenses, gains (losses) on disposal of assets, interest expense, equity in earnings (losses) from affiliates and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. We began allocating administration expenses from the Partnership to our Operating Companies using the Modified Massachusetts Formula Calculation ("MMFC") which is based on factors such as respective segments' gross margins, employee costs, and property and equipment.

The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the periods presented are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Costs allocated from ETP to operating subsidiaries:				
Midstream and intrastate transportation and storage operations	$ 15,776	$ 19,834	$ 6,761	$ 11,357
Interstate operations	4,922	5,750	2,613	4,388
Retail propane and other retail propane related operations	12,113	12,664	5,992	10,067
Total	$ 32,811	$ 38,248	$ 15,366	$ 25,812
Costs allocated from operating subsidiaries to ETP:				
Midstream and intrastate transportation and storage operations	$ 6,699	$ 10,649	$ 2,440	$ 5,221
Retail propane and other retail propane related operations	412	2,428	850	2,187
Total	$ 7,111	$ 13,077	$ 3,290	$ 7,408

The following tables present the financial information by segment for the following periods:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Revenues:				
Intrastate transportation and storage				
Revenues from external customers	$ 1,773,528	$ 3,379,424	$ 929,357	$ 3,085,940
Intersegment revenues	618,016	2,255,180	325,044	829,992
	2,391,544	5,634,604	1,254,401	3,915,932
Interstate transportation	270,213	244,224	76,000	178,663
Midstream				
Revenues from external customers	2,060,451	4,029,508	826,835	2,121,289
Intersegment revenues	380,709	1,312,885	339,478	732,207
	2,441,160	5,342,393	1,166,313	2,853,496
Retail propane and other retail propane related - revenues from external customers	1,292,583	1,624,010	511,258	1,284,867
All other:				
Revenues from external customers	20,520	16,201	5,892	121,278
Intersegment revenues	1,145	-	-	-
	21,665	16,201	5,892	121,278
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)
Total revenues	$ 5,417,295	$ 9,293,367	$ 2,349,342	$ 6,792,037
Cost of products sold:				
Intrastate transportation and storage	$ 1,393,295	$ 4,467,552	$ 964,568	$ 3,137,712
Midstream	2,116,279	4,986,495	1,043,191	2,632,187
Retail propane and other retail propane related	596,002	1,038,722	325,158	759,634
All other	16,350	13,376	5,259	110,872
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)
Total cost of products sold	$ 3,122,056	$ 6,938,080	$ 1,673,654	$ 5,078,206
Depreciation and amortization:				
Intrastate transportation and storage	$ 115,884	$ 92,979	$ 23,429	$ 64,423
Interstate transportation	48,297	37,790	12,305	27,972
Midstream	74,787	63,287	14,943	27,331
Retail propane and other retail propane related	83,476	79,717	24,537	70,833
All other	2,580	599	192	824
Total depreciation and amortization	$ 325,024	$ 274,372	$ 75,406	$ 191,383
Operating income (loss):				
Intrastate transportation and storage	$ 618,500	$ 710,070	$ 169,361	$ 479,820
Interstate transportation	138,233	124,676	29,657	95,650
Midstream	136,790	162,471	71,853	119,233
Retail propane and other retail propane related	229,229	114,564	46,747	124,263
All other	(8,658)	(2,032)	(796)	1,735
Selling general and administrative expenses not allocated to segments	(3,696)	(10,846)	(171)	(11,365)
Total operating income	$ 1,110,398	$ 1,098,903	$ 316,651	$ 809,336
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (468,420)	$ (357,541)	$ (103,375)	$ (279,986)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	33,619	(128,423)	(28,683)	29,081
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	1,913	8,115	(13,327)	1,129
Income tax expense	(9,229)	(3,808)	(9,949)	(11,391)
	(412,527)	(419,149)	(133,842)	(257,368)
Net income	$ 697,871	$ 679,754	$ 182,809	$ 551,968

	As of December 31, 2009	As of December 31, 2008	As of December 31, 2007	As of August 31, 2007
Total assets:				
Intrastate transportation and storage	$ 5,162,164	$ 4,911,770	$ 4,254,514	$ 3,814,391
Interstate transportation	3,313,837	2,487,078	1,834,941	1,653,363
Midstream	1,653,921	1,674,028	1,444,446	943,760
Retail propane and other retail propane related	1,784,353	1,810,953	1,778,426	1,593,863
All other	246,234	186,073	149,767	177,712
Total	$ 12,160,509	$ 11,069,902	$ 9,462,094	$ 8,183,089

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):				
Intrastate transportation and storage	$ 378,494	$ 993,886	$ 320,965	$ 827,859
Interstate transportation	99,341	720,186	167,343	1,345,637
Midstream	95,081	267,900	414,722	201,646
Retail propane and other retail propane related	62,953	130,358	47,553	65,125
All other	44,911	3,072	953	2,015
Total	$ 680,780	$ 2,115,402	$ 951,536	$ 2,442,282

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. Earnings per unit are computed on a stand-alone basis for each quarter and total year. HOLP's and Titan's businesses are seasonal due to weather conditions in their service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Sales to commercial and industrial customers are less weather sensitive. ETC OLP's business is also seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

2009:	Quarter Ended March 31	Quarter Ended June 30	Quarter Ended September 30	Quarter Ended December 31	Total Year
Revenues	$ 1,629,974	$ 1,151,690	$ 1,129,849	$ 1,505,782	$ 5,417,295
Gross Profit	670,835	525,697	451,701	647,006	2,295,239
Operating income	356,098	215,031	173,501	365,768	1,110,398
Net income	279,750	141,758	34,267	242,096	697,871
Limited Partners' interest in net income	151,067	104,053	46,824	139,159	441,103
Basic net income per limited partner unit	$ 0.68	$ 0.47	$ 0.21	$ 0.62	$ 1.98
Diluted net income per limited partner unit	$ 0.68	$ 0.47	$ 0.21	$ 0.62	$ 1.98

2008:	Quarter Ended March 31	June 30	September 30	December 31	Total Year
Revenues	$ 2,639,245	$ 2,653,351	$ 2,206,090	$ 1,794,681	$ 9,293,367
Gross Profit	659,527	529,279	572,636	593,845	2,355,287
Operating income	367,929	221,940	256,264	252,770	1,098,903
Net income	267,158	166,818	185,116	60,662	679,754
Limited Partners’ interest in net income	126,313	120,021	105,053	22,496	373,883
Basic net income per limited partner unit	$ 0.57	$ 0.54	$ 0.47	$ 0.10	$ 1.68
Diluted net income per limited partner unit	$ 0.57	$ 0.54	$ 0.47	$ 0.10	$ 1.68

17. SUPPLEMENTAL INFORMATION:

Following are the financial statements of the Parent Company, which are included to provide additional information with respect to the Parent Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 62	$ 62
Accounts receivable from related companies	97	459
Other current assets	1,287	163
Total current assets	1,446	684
ADVANCES TO AND INVESTMENT IN AFFILIATES	1,711,928	1,662,074
INTANGIBLES AND OTHER ASSETS, net	5,574	8,581
Total assets	$ 1,718,948	$ 1,671,339
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 178	$ 798
Accounts payable to affiliates	5,024	3,034
Accrued interest	1,480	9,222
Accrued and other current liabilities	127	912
Price risk management liabilities	64,704	47,453
Total current liabilities	71,513	61,419
LONG-TERM DEBT, less current maturities	1,573,951	1,571,642
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	73,332	121,710
COMMITMENTS AND CONTINGENCIES		
	1,718,796	1,754,771
PARTNERS' CAPITAL (DEFICIT):		
General Partner	368	155
Limited Partner - Common Unitholders (222,898,248 and 222,829,956 units authorized, issued and outstanding at December 31, 2009 and 2008, respectively	53,412	(15,762)
Accumulated other comprehensive loss	(53,628)	(67,825)
Total partners' capital (deficit)	152	(83,432)
Total liabilities and partners' capital (deficit)	$ 1,718,948	$ 1,671,339

STATEMENTS OF OPERATIONS

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ (4,970)	$ (6,453)	$ (2,875)	$ (8,496)
OTHER INCOME (EXPENSE):				
Interest expense	(74,049)	(91,822)	(37,071)	(104,405)
Equity in earnings of affiliates	526,383	551,835	168,547	435,247
Losses on non-hedged interest rate derivatives	(5,620)	(77,435)	(27,670)	(1,952)
Other, net	79	(1,056)	(8,128)	(405)
INCOME BEFORE INCOME TAXES	441,823	375,069	92,803	319,989
Income tax expense (benefit)	(650)	25	126	629
NET INCOME	442,473	375,044	92,677	319,360
GENERAL PARTNER'S INTEREST IN NET INCOME	1,370	1,161	287	1,048
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 441,103	$ 373,883	$ 92,390	$ 318,312

STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 468,969	$ 436,819	$ 77,360	$ 239,777
CASH FLOWS FROM INVESTING ACTIVITIES:				
Advances to and investment in subsidiaries	-	-	-	(1,200,000)
Net cash used in investing activities	-	-	-	(1,200,000)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	67,505	190,533	1,255	1,252,662
Principal payments on debt	(65,816)	(191,464)	-	(367,529)
Equity offerings	-	-	-	372,434
Cash distributions to Partners	(470,658)	(435,868)	(87,174)	(276,997)
Debt issuance costs	-	-	-	(11,881)
Net cash provided by (used in) financing activities	(468,969)	(436,799)	(85,919)	968,689
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	-	20	(8,559)	8,466
CASH AND CASH EQUIVALENTS, beginning of period	62	42	8,601	135
CASH AND CASH EQUIVALENTS, end of period	$ 62	$ 62	$ 42	$ 8,601

18. **<u>COMPARATIVE INFORMATION FOR THE FOUR MONTHS ENDED DECEMBER 31, 2007:</u>**

The unaudited financial information for the four month period ended December 31, 2006, contained herein is presented for comparative purposes only and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America. Certain financial statement amounts have been adjusted due to the adoption of new accounting standards in 2009. See Note 2.

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
REVENUES:		
Natural gas operations	$ 1,832,192	$ 1,668,667
Retail propane	471,494	409,821
Other	45,656	83,978
Total revenues	2,349,342	2,162,466
COSTS AND EXPENSES:		
Cost of products sold - natural gas operations	1,343,237	1,382,473
Cost of products sold - retail propane	315,698	256,994
Cost of products sold - other	14,719	50,376
Operating expenses	221,757	173,365
Depreciation and amortization	75,406	52,840
Selling, general and administrative	61,874	43,602
Total costs and expenses	2,032,691	1,959,650
OPERATING INCOME	316,651	202,816
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(103,375)	(82,979)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other income (expense), net	(34,734)	2,248
INCOME BEFORE INCOME TAX EXPENSE	192,758	129,040
Income tax expense	9,949	2,155
NET INCOME	182,809	126,885
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	90,132	50,204
NET INCOME ATTRIBUTABLE TO PARTNERS	92,677	76,681
GENERAL PARTNER'S INTEREST IN NET INCOME	287	290
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 92,390	$ 76,391
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.41	$ 0.45
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	222,829,916	170,691,287
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.41	$ 0.45
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	222,829,916	170,691,287

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in thousands)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
Net income	$ 182,809	$ 126,885
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17,970)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	(2,221)	158,916
Change in value of available-for-sale securities	(98)	(401)
	(20,289)	134,817
Comprehensive income	162,520	261,702
Less: Comprehensive income attributable to non-controlling interest	92,832	117,677
Comprehensive income attributable to partners	$ 69,688	$ 144,025

ENERGY TRANSFER EQUITY, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES:		
Net income	$ 182,809	$ 126,885
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	75,406	52,840
Amortization in interest expense	2,441	1,697
Provision for loss on accounts receivable	544	563
Gain on disposal of assets	(14,310)	(2,212)
Non-cash unit-based compensation expense	8,137	4,385
Non-cash executive compensation	442	-
Distributions in excess of (less than) equity in earnings of affiliates, net	4,448	(4,742)
Deferred income taxes	37	(3,199)
Other non-cash	(2,069)	-
Net change in operating assets and liabilities, net of acquisitions	(49,250)	218,586
Net cash provided by operating activities	208,635	394,803
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(337,092)	(67,089)
Capital expenditures	(651,228)	(336,473)
Contributions in aid of construction costs	3,493	4,984
Advances to and investment in affiliates	(32,594)	(953,247)
Proceeds from the sale of assets	21,478	7,644
Net cash used in investing activities	(995,943)	(1,344,181)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,742,802	2,911,149
Principal payments on debt	(1,062,272)	(1,941,610)
Subsidiary equity offering net of issue costs	234,887	-
Net proceeds from issuance of Common Units	-	213,287
Distributions to Partners	(87,174)	(39,867)
Debt issuance costs	(211)	(21,302)
Distributions to noncontrolling interests	(61,517)	(75,868)
Net cash provided by financing activities	766,515	1,045,789
INCREASE IN CASH AND CASH EQUIVALENTS	(20,793)	96,411
CASH AND CASH EQUIVALENTS, beginning of period	77,350	26,204
CASH AND CASH EQUIVALENTS, end of period	$ 56,557	$ 122,615
NON-CASH INVESTING AND FINANCING ACTIVITIES		
SUPPLEMENTAL CASH FLOW INFORMATION:		
NON-CASH INVESTING ACTIVITIES:		
Capital expenditures accrued	$ 87,622	$ 13,294
Gain from subsidiary issuance of common units (recorded in partners' capital)	$ 48,932	$ -
NON-CASH FINANCING ACTIVITIES:		
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 3,896	$ 532,631
Issuance of common units in connection with certain acquisitions	$ 1,400	$ -
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest, net of interest capitalized	$ 79,084	$ 50,480
Cash paid during the period for income taxes	$ 9,135	$ 6,197