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

FORM 8-K

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

Date of report (Date of earliest event reported): July 8, 2009

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1-14323**	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

1100 Louisiana, 10th Floor, Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

On January 1, 2009, Enterprise Products Partners L.P. ("Enterprise") and Enterprise Products GP, LLC ("EPGP") adopted Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements — an Amendment of ARB No. 51 ("SFAS 160"). EPGP is the general partner of Enterprise Products Partners L.P. Additionally, on January 1, 2009 Enterprise adopted Emerging Issues Task Force 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships ("EITF 07-4").

Attached as Exhibit 99.1 to this Current Report on Form 8-K and incorporated herein by reference are retrospectively adjusted versions of Items 6, 7, 7A, 8 and 15 – Exhibit 12.1 of Enterprise's Annual Report on Form 10-K for the fiscal year ended December 31, 2008, as filed with the Securities and Exchange Commission ("SEC") on March 2, 2009, which reflect the adoption of SFAS 160 and EITF 07-4 and the resulting change in the presentation and disclosure requirements relating to the financial statements for all periods presented in accordance with the requirements of SFAS 160 and EITF 07-4. All other Items of the Form 10-K remain unchanged. The information in Exhibit 99.1 does not reflect events or developments that occurred after March 2, 2009. More current information is contained in Enterprise's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2009 and other filings with the SEC. The Form 10-Q and other filings contain important information regarding events or developments that have occurred since the filing of the 2008 Form 10-K. This Current Report on Form 8-K should be read in conjunction with the portions of the Form 10-K that have not been updated herein.

Attached as Exhibit 99.2 to this Current Report on Form 8-K is a retrospectively adjusted version of the consolidated balance sheet of EPGP as of December 31, 2008, as filed with the SEC on March 12, 2009, which reflects the adoption of SFAS 160 and the resulting change in the presentation and disclosure requirements relating to the consolidated balance sheet presented in accordance with the requirements of SFAS 160.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This current 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 our 2008 Form 10-K and Part II, Item 1A of our quarterly report on Form 10-Q filed on May 11, 2009. 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.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Description
23.1	Consent of Deloitte & Touche LLP
23.2	Consent of Deloitte & Touche LLP
99.1	Recast Items 6, 7, 7A, 8 and 15 – Exhibit 12.1 of Enterprise Products Partners L.P.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2008
99.2	Recast Consolidated Balance Sheet of Enterprise Products GP, LLC on Form 8-K at December 31, 2008.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC, as General Partner

Date: July 8, 2009

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Senior Vice President, Controller and Principal Accounting Officer of Enterprise Products GP, LLC

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-36856, 333-82486, 333-115633, 333-115634, 333-150680 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-145709 of Enterprise Products Partners L.P. and Enterprise Products Operating LLC on Form S-3; and (iii) Registration Statement No. 333-142106 of Enterprise Products Partners L.P. on Form S-3 of our report dated March 2, 2009 (July 6, 2009 as to the effects of the adoption of SFAS 160 and EITF 07-4 and the related disclosures in Notes 1 and 3), relating to the consolidated financial statements of Enterprise Products Partners L.P. and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the retrospective adjustments related to the adoption of SFAS 160 and EITF 07-4), appearing in this Current Report on Form 8-K of Enterprise Products Partners L.P.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
July 6, 2009

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-36856, 333-82486, 333-115633, 333-115634, 333-150680 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-145709 of Enterprise Products Partners L.P. and Enterprise Products Operating LLC on Form S-3; and (iii) Registration Statement No. 333-142106 of Enterprise Products Partners L.P. on Form S-3 of our report dated March 2, 2009 (July 6, 2009 as to the effects of the adoption of SFAS 160 and the related disclosures in Notes 1 and 3), relating to the consolidated balance sheet of Enterprise Products GP, LLC and subsidiaries at December 31, 2008 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning the retrospective adjustments related to the adoption of SFAS 160), appearing in this Current Report on Form 8-K of Enterprise Products Partners L.P.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
July 6, 2009

Item 6. *Selected Financial Data*.

The following table presents selected historical consolidated financial data of our partnership, which has been adjusted for our adoption of Statement of Financial Accounting Standards No.160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 and Emerging Issues Task Force 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships. This information has been derived from and should be read in conjunction with the audited financial statements. In addition, information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this Current Report on Form 8-K. As presented in the table, amounts are in thousands (except per unit data).

	For the Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Operating results data: (1)					
Revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969	$ 12,256,959	$ 8,321,202
Income from continuing operations (2)	$ 995,397	$ 564,317	$ 608,762	$ 429,476	$ 265,608
Net income	$ 995,397	$ 564,317	$ 610,234	$ 425,268	$ 276,389
Net income attributed to Enterprise Products Partners L.P.	$ 954,021	$ 533,674	$ 601,155	$ 419,508	$ 268,261
Earnings per unit:					
Basic and Diluted	$ 1.84	$ 0.95	$ 1.20	$ 0.90	$ 0.84
Other financial data:					
Distributions per common unit (3)	$ 2.0750	$ 1.9475	$ 1.825	$ 1.698	$ 1.540

	As of December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Financial position data: (1)					
Total assets	$ 17,957,535	$ 16,608,007	$ 13,989,718	$ 12,591,016	$ 11,315,461
Long-term and current maturities of debt (4)	$ 9,108,410	$ 6,906,145	$ 5,295,590	$ 4,833,781	$ 4,281,236
Equity (5)	$ 6,478,637	$ 6,562,067	$ 6,609,362	$ 5,782,477	$ 5,399,825
Total units outstanding (excluding treasury) (5)	441,435	435,297	432,408	389,861	364,786

(1) In general, our historical operating results and financial position have been affected by numerous acquisitions since 2002. Our most significant transaction to date was the GulfTerra Merger, which was completed on September 30, 2004. The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. We accounted for the GulfTerra Merger and our other acquisitions using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective acquisition dates.
(2) Amounts presented for the years ended December 31, 2006, 2005 and 2004 are before the cumulative effect of accounting changes.
(3) Distributions per common unit represent declared cash distributions with respect to the four fiscal quarters of each period presented.
(4) In general, the balances of our long-term and current maturities of debt have increased over time as a result of financing all or a portion of acquisitions and other capital spending.
(5) We regularly issue common units through underwritten public offerings and, less frequently, in connection with acquisitions or other transactions. The September 2004 issuance of 104.5 million common units in connection with the GulfTerra Merger being our largest. For additional information regarding our equity and unit history, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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

For the years ended December 31, 2008, 2007 and 2006.

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

- § Cautionary Note Regarding Forward-Looking Statements.
- § Significant Relationships Referenced in this Discussion and Analysis.
- § Overview of Business.
- § Basis of Presentation.
- § General Outlook for 2009.
- § Recent Developments – Discusses significant developments during the year ended December 31, 2008.
- § 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, related party transactions, recent accounting pronouncements and other matters.

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

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

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

Significant Relationships Referenced in this Discussion and Analysis

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

References to "EPO" mean Enterprise Products Operating LLC as successor in interest by merger to Enterprise Products Operating L.P., which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

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 New York Stock Exchange ("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 "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

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." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). On May 7, 2007, Enterprise GP Holdings acquired noncontrolling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

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 private company affiliates of EPCO, Inc.

References to "EPCO" mean EPCO, Inc. and its wholly owned private company affiliates, which are related parties to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD."

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 four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. 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 conduct substantially all of our business through EPO. We are owned 98.0% by our limited partners and 2.0% by our general partner, EPGP. EPGP is owned 100.0% by Enterprise GP Holdings.

Basis of Presentation

Effective January 1, 2009, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 and Emerging Issue Task Force ("EITF") 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships. SFAS 160 established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our Consolidated Financial Statements. EITF 07-4 established the manner in which a mater limited partnership should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. The presentation and disclosure requirements of SFAS 160 and EITF 07-4 have been applied retrospectively to the consolidated financial statements, notes and disclosures included in this Current Report on Form 8-K.

General Outlook for 2009

The current global recession and financial crisis have impacted energy companies generally. The recession and related slowdown in economic activity has reduced demand for energy and related products, which in turn has generally led to significant decreases in the prices of crude oil, natural gas and NGLs. The financial crisis has resulted in the effective insolvency, liquidation or government intervention for a number of financial institutions, investment companies, hedge funds and highly leveraged industrial companies. This has had an adverse impact on the prices of debt and equity securities that has generally increased the cost and limited the availability of debt and equity capital.

Commercial Outlook

In 2008, there was significant volatility in the prices of refined products, crude oil, natural gas and NGLs. For example, the price of West Texas Intermediate crude oil ranged from a high near $147 per barrel in mid-2008 to $35 per barrel in January 2009; while the price of natural gas at the Henry Hub ranged from a high of over $13.00 per MMBtu in mid-2008 to $5.00 per MMBtu in January 2009. On a composite basis, the average price of NGLs declined from $1.68 per gallon for the third quarter of 2008 to $0.74 per gallon for the fourth quarter of 2008. The decrease in energy commodity prices combined with higher costs of capital have led many crude oil and natural gas producers to reconsider their drilling budgets for 2009. As a midstream energy company, we provide services for producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline.

The decrease in energy commodity prices has caused many oil and natural gas producers, which include many of our customers, to reduce their drilling budgets in 2009. This has resulted in a substantial reduction in the number of drilling rigs operating in the United States as surveyed by Baker Hughes Incorporated. The U.S. operating rig count decreased from a peak of 2,031 rigs in September 2008 to approximately 1,300 in February 2009. We expect oil and gas producers in our operating areas to reduce their drilling activity to varying degrees, which may lead to lower crude oil, natural gas and NGL production growth in the near term and, as a result, lower transportation, processing and marketing volumes for us than would have otherwise been the case.

In our natural gas processing business, we hedged approximately 80% of our equity NGL production margins for 2008 to mitigate the commodity price risk associated with these volumes. We have hedged approximately 67% of our expected equity NGL production margins for 2009. Since the hedges were consummated at prices that are significantly higher than current levels, we are expected to be partially insulated from lower natural gas processing margins in 2009.

The recession has reduced demand for midstream energy services and products by industrial customers. In the fourth quarter of 2008, the petrochemical industry experienced a dramatic destocking of inventories, which reduced demand for purity NGL products such as ethane, propane and normal butane. We expect that petrochemical demand will strengthen in early 2009 and have starting seeing signs of such demand through February 2009 as petrochemical customers have begun to restock their depleted inventories. This trend is also evidenced by slightly higher operating rates of U.S. ethylene crackers, which averaged approximately 70% of capacity in February 2009 as compared to 56% in December 2008. Four additional ethylene crackers were expected to recommence operations in February 2009. The average utilization rate for ethylene crackers in 2008 was approximately 80%. Based on currently available information, we expect that the operating rates of U.S. ethylene crackers will approximate 80% of capacity in 2009. We expect that crude oil prices will rebound from recent lows in the second half of 2009. As a result, we believe the petrochemical industry will continue to prefer NGL feedstocks over crude-based alternatives such as naphtha. In general, when the price of crude oil rises relative to that of natural gas, NGLs become more attractive as a source of feedstocks for the petrochemical industry.

The reduction in near-term demand for crude oil and NGLs has created a contango market (i.e., a market in which the price of a commodity is higher in future months than the current spot price) for these products, which, in turn, we are benefiting from through an increase in revenues earned by our storage assets in Mont Belvieu, Texas.

Liquidity Outlook

Debt and equity capital markets have also experienced significant recent volatility. The major U.S. and international equity market indices experienced significant losses in 2008, including losses of approximately 38% and 34% for the S&P 500 and Dow Jones Industrial Average, respectively. Likewise, the Alerian MLP Index, which is a recognized major index for publicly traded partnerships, lost approximately 42% of its value. The contraction in credit available to and investor redemptions of holdings in certain investment companies and hedge funds exacerbated the selling pressure and volatility in both the debt and equity capital markets. This has resulted in a higher cost of debt and equity capital for the public and private sector. Near term demand for equity securities through follow on offerings, including our common units, may be reduced due to the recent problems encountered by investment companies and hedge funds, both of which significantly participated in equity offerings over the past few years.

While the cost of capital has increased, we have demonstrated our ability to access the debt and equity capital markets during this distressed period. In December 2008, we issued $500.0 million of 9.75% senior notes. The higher cost of capital is evident when you compare the interest rate of the December 2008 senior notes offering to the $400.0 million of 5.65% senior notes that we issued in March 2008. On a positive note, our indicative cost of long-term borrowing has improved approximately 250 basis points in early 2009 in conjunction with the recent improvement in the debt capital markets. We believe that we will be able to either access the capital markets or utilize availability under our long-term multi-year revolving credit facility to refinance our $717.6 million of debt obligations that mature in 2009. In January 2009, we issued approximately 10.6 million of our common units at an effective annual distribution yield of 9.5%. Net offering proceeds of $225.6 million were used to reduce borrowings and for general partnership purposes.

The increase in the cost of capital has caused us to prioritize our respective internal growth projects to select those with higher rates of return. However, consistent with our business strategies, we continuously evaluate possible acquisitions of assets that would complement our current operations. Given the current state of the credit markets, we believe competition for such assets has decreased, which may result in opportunities for us to acquire assets at attractive prices that would be accretive to our partners and expand our portfolio of midstream energy assets.

Based on information currently available, we estimate that our capital spending for property, plant and equipment in 2009 will approximate $1.00 billion, which includes $820.0 million for growth capital projects and $180.0 million for sustaining capital expenditures. The 2009 forecast amounts for growth capital projects include amounts that are expected to be spent on the Texas Offshore Port System. See “Recent Developments – Texas Offshore Port System” for additional information regarding this joint venture.

We expect four of our significant construction projects to be completed and the assets placed into service during the first half of 2009. These projects include (i) the expansion of the Meeker natural gas processing plant, which began operations in February 2009, (ii) the Exxon Mobil central treating facility, (iii) the Sherman Extension natural gas pipeline, and (iv) the Shenzi Crude Oil Pipeline in the Gulf of Mexico. Substantially all of the financing to fund these projects has been completed. In 2009, we expect these projects to contribute significant new sources of revenue, operating income and cash flow from operations.

Hurricanes Gustav and Ike damaged a number of energy-related assets onshore and offshore along the Texas and Louisiana Gulf Coast in the summer of 2008, including certain of our offshore pipelines and platforms. Repairs are being completed on our affected assets and they are expected to be ready to return to service once third party production fields return to operational status over the course of 2009.

A few of our customers have experienced severe financial problems leading to a significant impact on their creditworthiness. These financial problems are rooted in various factors including the significant use of debt, current financial crises, economic recession and changes in commodity prices. We are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our respective credit position relating to amounts owed to us by certain customers. We cannot provide assurance that one or more of our customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows; however, we believe that we have provided adequate allowances for such customers.

We expect our proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under their credit facilities, to provide us with a foundation to meet our anticipated liquidity and capital requirements in 2009. We also believe that we will be able to access the capital markets in 2009 to maintain financial flexibility. Based on information currently available to us, we believe that we will maintain our investment grade credit ratings and meet our loan covenant obligations in 2009.

Recent Developments

The following information highlights our significant developments since January 1, 2008 through March 2, 2009.

Enterprise Products Partners Issues $225.6 million of Common Units

In January 2009, Enterprise Products Partners sold 10,590,000 common units representing limited partner interests (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. Net offering proceeds of $225.6 million were used to reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

High Island Offshore System Natural Gas Pipeline Resumes Operations

In December 2008, repairs were completed on the High Island Offshore System ("HIOS") pipeline that was severed in September 2008 during Hurricane Ike. Federal regulators, after approving our inspection and start-up procedures, authorized the partnership to resume full service on HIOS. The pipeline has the capacity to transport up to 1.8 Bcf/d of natural gas.

Operations Begin at White River Hub

In December 2008, we and Questar Pipeline Company ("Questar"), a subsidiary of Questar Corp., announced that service had begun on the White River Hub. Located in Rio Blanco County, Colo., the White River Hub currently connects our natural-gas processing plant at Meeker with four interstate natural gas pipelines: Rockies Express Pipeline LLC; Questar; Northwest Pipeline GP (including the Williams Willow Creek processing plant, which is currently under construction); and TransColorado Gas Transmission Company. Two more interstate pipelines, the Wyoming Interstate Company and Colorado Interstate Gas systems, are expected to be connected during the first quarter of 2009.

Sale of Interest in Companies to Duncan Energy Partners

In December 2008, Duncan Energy Partners acquired controlling equity interests in three midstream energy companies from affiliates of EPO in a transaction valued at $730.0 million. Duncan Energy Partners acquired a 51.0% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"); a 51.0% general partnership interest in Enterprise Intrastate LP ("Enterprise Intrastate"); and a 66.0% general partnership interest in Enterprise GC, LP ("Enterprise GC"). In the aggregate, these companies own more than 8,000 miles of natural gas pipelines with 5.6 Bcf/d of capacity; a leased natural gas storage facility with 6.8 Bcf of storage capacity; more than 1,000 miles of NGL pipelines; approximately 18 MMBbls of leased NGL storage capacity; and two NGL fractionators with a combined fractionation capacity of 87 MBPD. All of these assets are located in Texas. As consideration for this dropdown transaction, EPO received 37,333,887 Class B units valued at $449.5 million and $280.5 million in cash from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. For additional information regarding this transaction, see "Other Items – Duncan Energy Partners Transactions" within this Item 7.

EPO Issues $500.0 Million of Senior Notes

In December 2008, EPO sold $500.0 million in principal amount of 9.75% fixed-rate, unsecured senior notes due January 2014 ("Senior Notes O"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

EPO Executes $592.6 Million of Credit Facilities

In November 2008, EPO executed two senior unsecured credit facilities that provide the partnership with $592.6 million of incremental borrowing capacity. The facilities are comprised of a $375.0 million credit facility maturing in November 2009 and a 20.7 billion yen (approximately $217.6 million U.S. dollar equivalent) term loan maturing in March 2009. The Japanese term loan has a funded cost of approximately 4.93%, including the cost of related foreign exchange currency swaps. For additional information regarding these issuances of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

Texas Offshore Port System

In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC ("Motiva") and Exxon Mobil Corporation ("Exxon Mobil"), which have committed a combined 725 MBPD of crude oil to the projects. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the acquisition of requisite permits.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and TEPPCO have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of December 31, 2008, our investment in the Texas Offshore Port System was $35.9 million.

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie Pipeline Company ("Dixie") for $57.1 million. As a result of this transaction, we own 100.0% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane) to customers along the U.S. Gulf Coast and southeastern United States.

Reorganization of Commercial Management Team

In July 2008, Mr. A. J. Teague, Executive Vice President, was elected as a Director to the Boards of both our general partner and that of Duncan Energy Partners and as Chief Commercial Officer responsible for managing all of the commercial activities of the two partnerships. In connection with Mr. Teague's appointment as Chief Commercial Officer, certain members of our senior management team were realigned to report to Mr. Teague. Mr. Teague will continue to report to Michael A. Creel, President and Chief Executive Officer ("CEO") of Enterprise Products Partners.

Independence Trail and Hub Resume Operations

In April 2008, production at the Independence Hub natural gas platform was shut-in due to a leak in the flex-joint assembly where the Independence Trail export pipeline connects to the platform. In July 2008, repairs were completed and the Independence Hub platform and Trail pipeline returned to operation. Our Independence Trail export pipeline recorded $17.0 million of expense associated with the flex-joint repairs. We have submitted a claim with our insurance carriers regarding the flex-joint repair costs. To the extent that we receive cash proceeds from this claim in the future, such amounts would be recorded as income in the period of receipt.

EPO Issues $1.10 Billion of Senior Notes

In April 2008, EPO sold $400.0 million in principal amount of 5.65% fixed-rate, unsecured senior notes due April 2013 ("Senior Notes M") and $700.0 million in principal amount of 6.50% fixed-rate, unsecured senior notes due January 2019 ("Senior Notes N"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

Duncan Energy Partners' Shelf Registration Statement

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. As of February 2, 2009, Duncan Energy Partners has issued $0.5 million in equity securities under this registration statement.

Pioneer Cryogenic Natural Gas Processing Facility Commences Operations

In February 2008, we commenced operations of the Pioneer cryogenic natural gas processing facility. Located near the Opal Hub in southwestern Wyoming, this new facility is designed to process up to 700 MMcf/d of natural gas and extract as much as 30 MBPD of NGLs. We intend to maintain the operational capability of our Pioneer silica gel natural gas processing plant, which is located adjacent to the Pioneer cryogenic plant, as a back-up to provide producers with additional assurance of our processing capability at the complex. NGLs extracted at our Pioneer complex are transported on our Mid-America Pipeline System and ultimately to our Hobbs and Mont Belvieu NGL fractionators.

In late March 2008, operations at our Pioneer cryogenic natural gas processing facility were temporarily suspended following a release of natural gas and subsequent fire. No injuries resulted from the incident, which was restricted to a small area within the plant. The facility resumed operations in April 2008.

Results of Operations

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. 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 senior 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 as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, cumulative effect of changes in accounting principles, extraordinary charges and earnings attributable to noncontrolling interests. 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 intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in consolidation.

We include equity in earnings 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 also 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 stand alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100.0% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100.0% basis in our consolidated statistical data.

For additional information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
2006 Averages	$ 7.24	$ 66.09	$ 0.66	$ 1.01	$ 1.20	$ 1.24	$ 1.44	$ 0.47	$ 0.41
2007 Averages	$ 6.86	$ 72.30	$ 0.79	$ 1.21	$ 1.42	$ 1.49	$ 1.68	$ 0.52	$ 0.47
2008									
1st Quarter	$ 8.03	$ 97.91	$ 1.01	$ 1.47	$ 1.80	$ 1.87	$ 2.12	$ 0.61	$ 0.54
2nd Quarter	$ 10.94	$ 123.88	$ 1.05	$ 1.70	$ 2.05	$ 2.08	$ 2.64	$ 0.70	$ 0.67
3rd Quarter	$ 10.25	$ 118.01	$ 1.09	$ 1.68	$ 1.97	$ 1.99	$ 2.52	$ 0.78	$ 0.66
4th Quarter	$ 6.95	$ 58.32	$ 0.42	$ 0.80	$ 0.90	$ 0.96	$ 1.09	$ 0.37	$ 0.22
2008 Averages	$ 9.04	$ 99.53	$ 0.89	$ 1.41	$ 1.68	$ 1.72	$ 2.09	$ 0.62	$ 0.52

(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 ("OPIS") and Chemical Market 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.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures and reflect the periods in which we 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 the Year Ended December 31,		
	2008	**2007**	**2006**
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,819	1,666	1,577
NGL fractionation volumes (MBPD)	429	394	312
Equity NGL production (MBPD)	108	88	63
Fee-based natural gas processing (MMcf/d)	2,524	2,565	2,218
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	7,477	6,632	6,012
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,408	1,641	1,520
Crude oil transportation volumes (MBPD)	169	163	153
Platform natural gas processing (MMcf/d)	632	494	159
Platform crude oil processing (MBPD)	15	24	15
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	86	90	81
Propylene fractionation volumes (MBPD)	58	68	56
Octane additive production volumes (MBPD)	9	9	9
Petrochemical transportation volumes (MBPD)	108	105	97
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,096	1,934	1,827
Natural gas transportation volumes (BBtus/d)	8,885	8,273	7,532
Equivalent transportation volumes (MBPD) (1)	4,434	4,111	3,809

(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 thousands):

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969
Operating costs and expenses	20,460,964	16,009,051	13,089,091
General and administrative costs	90,550	87,695	63,391
Equity in earnings of unconsolidated affiliates	59,104	29,658	21,565
Operating income	1,413,246	883,037	860,052
Interest expense	400,686	311,764	238,023
Provision for income taxes	26,401	15,257	21,323
Net income	995,397	564,317	610,234
Net income attributable to noncontrolling interest	41,376	30,643	9,079
Net income attributable to Enterprise Products Partners L.P.	954,021	533,674	601,155

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

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Gross operating margin by segment:			
NGL Pipelines & Services	$ 1,290,458	$ 812,521	$ 752,548
Onshore Natural Gas Pipelines & Services	411,344	335,683	333,399
Offshore Pipeline & Services	188,083	171,551	103,407
Petrochemical Services	167,584	172,313	173,095
Total segment gross operating margin	$ 2,057,469	$ 1,492,068	$ 1,362,449

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes and the cumulative effect of change in accounting principles, 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 thousands):

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
Sales of NGLs	$ 14,680,607	$ 11,757,895	$ 9,442,403
Sales of other petroleum and related products	2,387	3,027	2,353
Midstream services	698,957	710,447	745,187
Total	15,381,951	12,471,369	10,189,943
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	3,091,296	1,481,569	1,103,169
Midstream services	480,802	588,526	595,726
Total	3,572,098	2,070,095	1,698,895
Offshore Pipelines & Services:			
Sales of natural gas	100	101	307
Sales of other petroleum and related products	11,144	12,086	4,562
Midstream services	257,166	211,624	140,994
Total	268,410	223,811	145,863
Petrochemical Services:			
Sales of other petroleum and related products	2,593,856	2,115,429	1,873,722
Midstream services	89,341	69,421	82,546
Total	2,683,197	2,184,850	1,956,268
Total consolidated revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969

Our revenues are derived from a wide customer base. During 2008, our largest customer was LyondellBasell Industries (“LBI”) and its affiliates, which accounted for 9.6% of our consolidated revenues. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

Comparison of 2008 with 2007

Revenues for 2008 were $21.91 billion compared to $16.95 billion for 2007. The $4.96 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 $5.01 billion of the year-to-year increase in consolidated revenues associated with our NGL, natural gas and petrochemical 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.

Operating costs and expenses were $20.46 billion for 2008 versus $16.01 billion for 2007. The $4.45 billion year-to-year increase in consolidated operating costs and expenses is primarily due to higher cost of sales associated with our marketing activities. The cost of sales of our marketing activities increased $3.57 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 $306.3 million year-to-year primarily due to higher energy commodity prices. Consolidated operating costs and expenses attributable to newly constructed assets we placed into service after January 1, 2007 increased $414.3 million year-to-year. General and administrative costs increased $2.9 million year-to-year.

Changes in our revenues and costs and expenses year-to-year are explained in part 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. 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) averaged $9.04 per MMBtu during 2008 versus $6.86 per MMBtu during 2007. See "Results of Operations - Selected Price and Volumetric Data" within this Item 7 for additional historical energy commodity pricing information.

Equity in earnings from our unconsolidated affiliates was $59.1 million for 2008 compared to $29.7 million for 2007, a $29.4 million year-to-year increase. Equity in earnings from our investment in Cameron Highway Oil Pipeline Company ("Cameron Highway") increased $27.6 million year-to-year due to higher transportation volumes and lower interest expense. On a 100.0% basis, Cameron Highway had crude oil transportation volumes of 161 MBPD during 2008 compared to 88 MBPD during 2007. Equity in earnings from our investment in Jonah Gas Gathering Company ("Jonah") increased $12.1 million year-to-year. We earned a fixed 19.4% interest in Jonah during the third quarter of 2007 upon completion of certain achievements with respect to the Phase V Expansion of the Jonah Gathering System. Equity in earnings from our investment in Nemo Gathering Company, LLC ("Nemo") increased $5.0 million year-to-year due to the recognition of a non-cash impairment charge in the second quarter of 2007. Collectively, equity earnings from our other investments decreased $15.3 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 $1.41 billion compared to $883.0 million for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $530.2 million increase in operating income year-to-year.

Interest expense increased to $400.7 million for 2008 from $311.8 million for 2007. The $88.9 million year-to-year increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008 and Senior Notes L in the third quarter of 2007. Average debt principal outstanding during 2008 was $7.93 billion compared to $6.18 billion during 2007.

Provision for income taxes increased $11.1 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 $4.4 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.

Net income attributable to noncontrolling interest increased $10.7 million year-to-year attributable to the public unitholders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of items noted in the previous paragraphs, net income attributable to Enterprise Products Partners L.P. increased $420.3 million year-to-year to $954.0 million for 2008 compared to $533.7 million for 2007.

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 $47.9 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin was reduced by $77.0 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 "Other Items – Insurance Matters" included within this Item 7.

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 $1.29 billion for 2008 compared to $812.5 million for 2007. The $478.0 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 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 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 southern Louisiana.

Gross operating margin from our NGL pipelines and related storage business was $369.2 million for 2008 compared to $302.2 million for 2007. Total NGL transportation volumes increased to 1,819 MBPD during 2008 from 1,666 MBPD during 2007. The $67.0 million year-to-year increase in gross operating margin from this business is primarily due to improved results from our Mid-America and Seminole Pipeline Systems and our Mont Belvieu storage complex. 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.

Gross operating margin from the remainder of our NGL pipeline and storage assets increased $7.9 million year-to-year attributable to (i) higher transportation volumes on our Dixie Pipeline System and our Lou-Tex NGL Pipeline and (ii) lower maintenance and pipeline integrity expenses on our Dixie Pipeline and South Louisiana Pipeline System. 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 $104.8 million for 2008 compared to $88.4 million for 2007. Fractionation volumes increased from 394 MBPD during 2007 to 429 MBPD during 2008. Gross operating margin from our Hobbs fractionator increased $26.7 million year-to-year. Our Hobbs fractionator was placed into service during August 2007 and contributed a 41 MBPD year-to-year increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $10.3 million year-to-year primarily due to downtime and lower volumes at our Norco, South Texas and Baton Rouge fractionators and a combined $0.9 million of hurricane-related property damage repair expenses in 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $411.3 million for 2008 compared to $335.7 million for 2007, a $75.6 million year-to-year increase. Our onshore natural gas transportation volumes were 7,477 BBtus/d during 2008 compared to 6,632 BBtus/d during 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business increased $64.7 million year-to-year to $371.9 million for 2008 from $307.2 million for 2007. Collectively, gross operating margin from our natural gas pipelines increased $75.1 million year-to-year 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) increased equity earnings from our investment in Jonah. 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 marketing activities decreased $10.4 million year-to-year primarily due to non-cash mark-to-market related charges that are expected to be recouped in cash in future periods extending through 2009.

Our natural gas marketing business increased significantly during 2008. These marketing activities have four primary objectives: (i) to mitigate risk; (ii) maximize the use of our natural gas assets; (iii) to provide real-time market intelligence; and (iv) to link our noncontiguous natural gas assets together to enhance the profitability of such operations. To achieve these objectives, our natural gas marketing activities transact with various parties to provide transportation, balancing, storage, supply and sales services. The majority of our natural gas marketing activities are focused on the Gulf Coast and Rocky Mountain regions.

Our natural gas marketing business acquires a significant portion of the natural gas it sells from our processing plants and additional supplies from third parties at pipeline interconnects to facilitate incremental throughput on our natural gas transportation pipelines. This purchased gas is then sold to industrial consumers, utilities and power plants at prices that include a transportation fee. In addition, sales are made to third party marketing companies at industry hub locations in order to balance our supply/demand portfolio. Our purchase and sale transactions are typically based on published daily or monthly index prices. We utilize financial instruments to hedge various transactions within our natural gas marketing business.

We use third party transportation and storage capacity to link together our non-contiguous natural gas assets. Our natural gas marketing business contracts with third party transportation and storage providers to provide services on both a firm and interruptible basis. This strategy allows us to complement and strengthen our portfolio of natural gas assets.

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.

Offshore Pipelines & Services. Gross operating margin from this business segment was $188.1 million for 2008 compared to $171.6 million for 2007. The $16.5 million year-to-year increase in segment gross operating margin is primarily due to contributions from our Independence Hub and Trail project and improved results from our Cameron Highway Oil Pipeline. Results from this business segment for 2008 were negatively impacted by (i) downtime and $17.0 million of repair expenses associated with a leak on the Independence Trail pipeline and (ii) the effects of Hurricanes Gustav and Ike including downtime, reduced volumes and $37.2 million of property damage repair expenses. 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 $36.2 million for 2008 versus $21.1 million for 2007, a $15.1 million year-to-year increase. Gross operating margin increased $27.6 million year-to-year due to increased equity in earnings from Cameron Highway, which benefited from higher crude oil transportation volumes and lower 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 $12.5 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-party 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. 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 Services. Gross operating margin from this business segment was $167.6 million for 2008 compared to $172.3 million for 2007. Gross operating margin from our propylene fractionation and pipeline business was $83.1 million for 2008 compared to $62.6 million for 2007. The $20.5 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 our butane isomerization business 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 higher NGL prices, which resulted in higher by-product sales revenues 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 the third quarter of 2008.

Gross operating margin from our octane enhancement business 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 the third quarter of 2008 and the effects of Hurricane Ike.

Comparison of 2007 with 2006

Revenues for 2007 were $16.95 billion compared to $13.99 billion for 2006. The $2.96 billion year-to-year increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices in 2007 relative to 2006. These factors accounted for a $2.94 billion increase in consolidated revenues associated with our marketing activities. Revenues from business interruption insurance proceeds totaled $36.1 million in 2007 compared to $63.9 million in 2006.

Operating costs and expenses were $16.01 billion for 2007 versus $13.09 billion for 2006. The $2.92 billion year-to-year increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our NGL, natural gas and petrochemical products increased $2.45 billion year-to-year as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $185.7 million year-to-year as a result of higher energy commodity prices in 2007 relative to 2006. Operating costs and expenses associated with assets we constructed and placed into service or acquired since January 1, 2006 increased $188.1 million year-to-year.

General and administrative costs were $87.7 million for 2007 compared to $63.4 million for 2006. The $24.3 million year-to-year increase in general and administrative costs is primarily due to the recognition of a severance obligation during 2007 and an increase in legal fees.

Changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.19 per gallon during 2007 versus $1.00 per gallon during 2006. The Henry Hub market price of natural gas averaged $6.86 per MMBtu during 2007 versus $7.24 per MMBtu during 2006. For additional historical energy commodity pricing information, see “Results of Operations – Selected Price and Volumetric Data” within this Item 7.

Equity in earnings from unconsolidated affiliates were $29.7 million for 2007 compared to $21.6 million for 2006. Equity in earnings from our investment in Jonah increased $9.1 million year-to-year due to an increase in our ownership interest in Jonah effective during the third quarter of 2007. Equity in earnings for 2007 include a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to a non-cash impairment charge of $7.4 million in 2006 related to our investment in Neptune Pipeline Company, L.L.C. (“Neptune”). Collectively, equity in earnings from our other unconsolidated affiliates decreased $1.4 million year-to-year primarily due to the sale of our investment in Coyote Gas Treating, LLC in August 2006.

Operating income for 2007 was $883.0 million compared to $860.1 million for 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity in earnings from unconsolidated affiliates contributed to the $22.9 million increase in operating income year-to-year.

Interest expense increased $73.7 million year-to-year primarily due to our issuance of junior subordinated notes in the second quarter of 2007 and third quarter of 2006 and the issuance of Senior Notes L in the third quarter of 2007. Our consolidated interest expense for 2007 includes $11.6 million associated with Duncan Energy Partners’ credit facility. Our average debt principal outstanding was $6.18 billion in 2007 compared to $4.92 billion in 2006. Net income attributable to noncontrolling interest increased $21.6 million year-to-year attributable to the public unit holders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of items noted in the previous paragraphs, net income attributable to Enterprise Products Partners L.P. decreased $67.5 million year-to-year to $533.7 million in 2007 compared to $601.2 million in 2006. Net income attributable to Enterprise Products Partners L.P. for 2006 includes a $1.5 million benefit relating to the cumulative effect of change in accounting principle. For additional information regarding the cumulative effect of change in accounting principle we recorded in 2006, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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 $812.5 million for 2007 compared to $752.5 million for 2006. Gross operating margin for 2007 includes $32.7 million of proceeds from business interruption insurance claims compared to $40.4 million of proceeds during 2006. Strong demand for NGLs in 2007 compared to 2006 led to higher natural gas processing margins, increased volumes of natural gas processed under fee-based contracts and higher NGL throughput volumes at certain of our pipelines and fractionation facilities. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from NGL pipelines and storage was $302.2 million for 2007 compared to $265.7 million for 2006. Total NGL transportation volumes increased to 1,666 MBPD during 2007 from 1,577 MBPD during 2006. The $36.5 million year-to-year increase in gross operating margin is primarily due to higher pipeline transportation and NGL storage volumes at certain of our facilities and higher transportation fees charged to shippers on our Mid-America Pipeline System. Our DEP South Texas NGL Pipeline contributed $21.1 million of gross operating margin and 73 MBPD of NGL transportation volumes during 2007. The increase in gross operating margin year-to-year was partially offset by lower volumes and higher costs resulting from the November 2007 rupture of the Dixie Pipeline and a one-time benefit in 2006 for the settlement of a pipeline contamination incident.

Gross operating margin from our natural gas processing and related NGL marketing business was $389.1 million for 2007 compared to $359.7 million for 2006. The $29.4 million increase in gross operating margin year-to-year is largely due to improved results from our South Texas, Louisiana and Chaco natural gas processing facilities attributable to higher volumes and equity NGL sales revenues, all of which were partially offset by expenses associated with start-up delays at our Meeker and Pioneer natural gas processing plants. Fee-based processing volumes increased to 2.6 Bcf/d during 2007 from 2.2 Bcf/d during 2006. Equity NGL production increased to 88 MBPD during 2007 from 63 MBPD during 2006.

Gross operating margin from NGL fractionation was $88.4 million for 2007 compared to $86.8 million for 2006. Fractionation volumes increased from 312 MBPD during 2006 to 394 MBPD during 2007. The year-to-year increase in gross operating margin of $1.6 million is primarily due to higher volumes at our Norco NGL fractionator during 2007 relative to 2006. Our Norco NGL fractionator returned to normal operating rates in the second quarter of 2006 after suffering a reduction of fractionation volumes due to the effects of Hurricane Katrina. Gross operating margin attributable to our Hobbs NGL fractionator, which became operational in August 2007, was largely offset by start-up expenses. Fractionation volumes for 2007 include 36 MBPD from our Hobbs fractionator.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $335.7 million for 2007 compared to $333.4 million for 2006. Our total onshore natural gas transportation volumes were 6,632 BBtus/d for 2007 compared to 6,012 BBtus/d for 2006. Gross operating margin from our onshore natural gas pipeline business was $307.2 million for 2007 compared to $312.3 million for 2006. The $5.1 million year-to-year decrease in gross operating margin from this business is largely due to higher operating costs on our Acadian Gas System, Carlsbad Gathering System and our Texas Intrastate System.

Results from our onshore natural gas pipeline business for 2007 include $5.5 million of gross operating margin from our Piceance Creek Gathering System, which we acquired in December 2006. Equity in earnings from our investment in Jonah increased $9.1 million year-to-year. The Piceance Creek Gathering System and our net share of the gathering volumes on the Jonah Gathering System contributed 789 BBtus/d, collectively, of natural gas gathering volumes during 2007.

Gross operating margin from our natural gas storage business was $28.4 million for 2007 compared to $21.1 million for 2006. The $7.3 million year-to-year increase in gross operating margin is largely due to our Wilson natural gas storage facility attributable to lower repair costs in 2007 relative to 2006 and a 2006 loss on the sale of cushion gas. Our Wilson natural gas storage facility remained out of operation through 2007 due to ongoing repairs. Gross operating margin from our Petal facility includes an $8.4 million benefit in 2006 for a well measurement gain.

Offshore Pipelines & Services. Gross operating margin from this business segment was $171.6 million for 2007 compared to $103.4 million for 2006, a year-to-year increase of $68.2 million. Our Independence project contributed $85.0 million of gross operating margin during 2007 on average natural gas throughput of 423 BBtus/d. Segment gross operating margin for 2007 includes $3.4 million of proceeds from business interruption insurance claims compared to $23.5 million of proceeds in 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platform services business was $111.7 million for 2007 compared to $34.6 million for 2006. The $77.1 million year-to-year increase in gross operating margin is primarily due to our start up of the Independence Hub Platform in 2007, which contributed $63.6 million of gross operating margin in 2007. In addition, gross operating margin from the remainder of this business increased $13.5 million year-to-year primarily due to higher volumes during 2007 versus 2006. Our net platform natural gas processing volumes increased to 494 MMcf/d in 2007 from 159 MMcf/d in 2006.

Gross operating margin from our offshore natural gas pipeline business was $35.4 million for 2007 compared to $22.4 million for 2006. Offshore natural gas transportation volumes were 1,641 BBtus/d during 2007 versus 1,520 BBtus/d during 2006. Our Independence Trail Pipeline reported $21.4 million of gross operating margin and 423 BBtus/d of transportation volumes for 2007. Results from our Independence Trail Pipeline were partially offset by a decrease in volumes and revenues from our Viosca Knoll Gathering System and Constitution Gas Pipeline. Gross operating margin for 2007 includes a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to charge of $7.4 million in 2006 related to our investment in Neptune.

Gross operating margin from our offshore crude oil pipeline business was $21.1 million for 2007 versus $23.0 million for 2006. The $1.9 million year-to-year decrease in gross operating margin is primarily due to lower transportation volumes on our certain of our offshore crude oil pipelines and higher operating costs on our Poseidon Oil Pipeline System during 2007 relative to 2006. An increase in revenues year-to-year on our Cameron Highway Oil Pipeline System attributable to higher volumes was more than offset by a one-time expense of $8.8 million associated with the early termination of Cameron Highway's credit facility. Crude oil transportation volumes on our Cameron Highway Oil Pipeline System net to our ownership interest were 44 MBPD during 2007 compared to 32 MBPD during 2006. Total offshore crude oil transportation volumes were 163 MBPD during 2007 versus 153 MBPD during 2006.

Petrochemical Services. Gross operating margin from this business segment was $172.3 million for 2007 compared to $173.1 million for 2006. Gross operating margin from our butane isomerization business was $91.4 million for 2007 compared to $73.2 million for 2006. The $18.2 million year-to-year increase in gross operating margin is attributable to higher processing volumes and by-products sales revenues. Butane isomerization volumes were 90 MBPD for 2007 compared to 81 MBPD for 2006.

Gross operating margin from our propylene fractionation and pipeline activities was $62.6 million for 2007 versus $63.4 million for 2006. The $0.8 million year-to-year decrease in gross operating margin is primarily attributable to higher operating costs and expenses attributable to our propylene pipelines and our propylene storage and export facility. Petrochemical transportation volumes were 105 MBPD during 2007 compared to 97 MBPD during 2006. Gross operating margin from octane enhancement was $18.3 million for 2007 compared to $36.6 million for 2006. The year-to-year decrease of $18.3 million is primarily due to lower sales margins in 2007 relative to 2006. Octane enhancement production was 9 MBPD during 2007 and 2006.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term 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 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, 2008, we had $35.4 million of unrestricted cash on hand and approximately $1.30 billion of available credit under EPO's Multi-Year Revolving Credit Facility and a new credit facility executed in November 2008. We had approximately $9.05 billion in principal outstanding under consolidated debt agreements at December 31, 2008. In total, our consolidated liquidity at December 31, 2008 was approximately $1.49 billion, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that would allow us to issue an unlimited amount of debt and equity securities for general partnership purposes. In April 2008, EPO issued $1.10 billion in principal amount of fixed-rate, unsecured senior notes under this registration statement.

In December 2008, EPO also issued $500.0 million in principal amount of fixed-rate, unsecured senior notes. Net proceeds from these senior note offerings were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. We used the net proceeds of $225.6 million from the offering 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.

During 2003, we instituted a distribution reinvestment plan ("DRIP"). We have a registration statement on file with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our 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 our partnership. During the year ended December 31, 2008, we issued 5,368,310 common units in connection with our DRIP, which generated proceeds of $134.7 million from plan participants. In November 2008, affiliates of EPCO reinvested $67.0 million in connection with the DRIP.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10.0% discount through payroll deductions. During the year ended December 31, 2008, we issued 155,636 common units to employees under this plan, which generated proceeds of $4.5 million.

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. In December 2008, Duncan Energy Partners issued $0.5 million in equity securities under its registration statement.

For information regarding our public debt obligations or partnership equity, see Notes 14 and 15, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

Letter of Credit Facility

In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility, which remained outstanding at December 31, 2008. This letter of credit facility does not reduce the amount available under our Multi-Year Revolving Credit Facility.

Credit Ratings of EPO

At March 2, 2009, the investment-grade credit ratings of EPO's senior unsecured debt securities remain unchanged from 2008 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 $1.25 billion of fixed/floating unsecured junior subordinated notes that EPO issued in 2006 and 2007, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50.0% equity treatment and Fitch Ratings assigned 75.0% equity treatment.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, EPO entered into a $54.0 million, ten-year, fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's Investor Services declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, EPO would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

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.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Net cash flows provided by operating activities	$ 1,237.1	$ 1,590.9	$ 1,175.1
Cash used in investing activities	2,411.9	2,553.6	1,689.3
Cash provided by financing activities	1,171.0	979.4	495.0

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 and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; 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 our 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 expense paid by EPCO, changes in the fair market value of financial 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 2008 with 2007

Operating Activities. Net cash flows provided by operating activities were $1.24 billion for 2008 compared to $1.59 billion for 2007. The $353.9 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 $262.6 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 $262.6 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 proceeds from business interruption and property damage claims, see Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

- Cash distributions received from unconsolidated affiliates increased $25.0 million year-to-year primarily due to increased distributions from Jonah and Cameron Highway.

§ Cash payments for interest increased $116.3 million year-to-year primarily due to increased borrowings to finance our capital spending program.

Investing Activities. Cash used in investing activities was $2.41 billion for 2008 compared to $2.55 billion for 2007. The $141.7 million 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 $174.6 million year-to-year. For additional information related to our capital spending program, see "Capital Spending" included within this Item 7.

§ Cash outlays for investments in and advances to unconsolidated affiliates decreased by $208.9 million year-to-year. 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 50.0% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt. In addition, cash contributions to Jonah decreased $83.0 million year-to-year as a result of the completion of an expansion project in June 2008. Expenditures for 2008 include $22.5 million in contributions to White River Hub, LLC, $36.0 million to acquire a 49.0% interest in Skelly-Belvieu Pipeline Company, L.L.C., and $35.9 million in contributions to the Texas Offshore Port System joint venture.

§ An $85.4 million increase in restricted cash (a cash outflow) due to margin requirements primarily due to our hedging activities. See Item 7A of this Current Report on Form 8-K for information regarding our interest rate and commodity risk hedging portfolios.

§ Cash used for business combinations increased $166.4 million year-to-year primarily due to the acquisition of a 100.0% membership interest in Great Divide Gathering LLC for $125.2 million, the acquisition of the remaining interests in Dixie for $57.1 million and the acquisition of additional interests in Tri-States NGL Pipeline, L.L.C ("Tri-States") for $18.7 million.

Financing Activities. Cash provided by financing activities was $1.17 billion for 2008 compared to $979.4 million for 2007. This $191.6 million increase in cash provided by financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $588.9 million year-to-year. In April 2008, EPO sold $400.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes M") and $700.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes N"). In November 2008, EPO executed a Japanese yen term loan agreement in the amount of 20.7 billion yen (approximately $217.6 million U.S. dollar equivalent). In December 2008, EPO sold $500.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes O"). We used the proceeds from these borrowings primarily to repay amounts borrowed under our Multi-Year Revolving Credit Facility and, to a lesser extent, for general partnership purposes. For information regarding our consolidated debt obligations, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

§ Net proceeds from the issuance of our common units increased $73.6 million year-to-year due to increased participation in our DRIP.

§ Contributions from noncontrolling interest decreased $302.9 million year-to-year primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated proceeds of $290.5 million.

§ Cash distributions to our partners and noncontrolling interest increased $103.2 million year-to-year primarily due to increases in our common units outstanding and quarterly distribution rates, increases in the quarterly distribution rates of Duncan Energy Partners and distributions paid to Independence Hub's joint venture partner.

- § The early termination and settlement of interest rate hedging financial instruments during 2008 resulted in net cash payments of $14.4 million compared to net cash receipts of $48.9 million during the same period in 2007, which resulted in a $63.3 million decrease in financing cash flows between years.

Comparison of 2007 with 2006

Operating activities. Net cash flows provided by operating activities was $1.59 billion for 2007 compared to $1.18 billion for 2006. The $415.9 million year-to-year increase in net cash flows provided by operating activities was primarily due to the following:

- § Our net cash flows from consolidated businesses (excluding distributions received from unconsolidated affiliates and cash payments for interest and taxes) increased $436.8 million year-to-year. The improvement in cash flow is generally due to increased gross operating margin and the timing of related cash collections and disbursements between periods. The $436.8 million total year-to-year increase also reflects a $42.1 million increase in cash proceeds we received from insurance claims related to certain named storms.

- § Cash distributions received from unconsolidated affiliates increased $30.6 million year-to-year primarily due to improved earnings from our Gulf of Mexico investments, which were negatively impacted during 2006 as a result of the lingering effects of Hurricanes Katrina and Rita.

- § Cash payments for interest increased $56.2 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt balance for 2007 was $6.26 billion compared to $4.93 billion for 2006.

- § Cash payments for taxes decreased $4.7 million year-to-year.

Investing activities. Cash used in investing activities was $2.55 billion for 2007 compared to $1.69 billion for 2006. The $864.3 million year-to-year increase in cash used for investing activities was primarily due to the following:

- § An $847.7 million increase in capital spending for property, plant and equipment (net of contributions in aid of construction costs) and a $194.6 million increase in investments in unconsolidated affiliates, partially offset by a $240.7 million decrease in cash outlays for business combinations.

- § We contributed $216.5 million to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50.0% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt.

- § During 2006, we paid $100.0 million for Piceance Creek Pipeline, LLC and $145.2 million for the Encinal acquisition. Our spending for business combinations during 2007 was limited and primarily due to the $35.0 million we paid to acquire the South Monco pipeline business.

- § Restricted cash increased $38.6 million (a cash outflow) year-to-year.

Financing activities. Cash provided by financing activities was $979.4 million for 2007 versus $495.0 million for 2006. The $484.4 million year-to-year increase in cash provided by financing activities was primarily due to the following:

- § Net borrowings under our consolidated debt agreements increased $1.10 billion year-to-year. In May 2007, EPO sold $700.0 million in principal amount of fixed/floating unsecured junior subordinated notes (Junior Notes B”). In September 2007, EPO sold $800.0 million in principal amount of fixed-rate unsecured senior notes (“Senior Notes L”) and in October 2007, EPO repaid $500.0 million in principal amount of fixed-rate unsecured senior notes (“Senior Notes E”).

- § Net proceeds from the issuance of our common units decreased $788.0 million year-to-year. We completed underwritten equity offerings in March and September of 2006 that generated net proceeds of $750.8 million reflecting the sale of 31,050,000 common units.

- § Contributions from noncontrolling interest increased $275.4 million year-to-year primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated net proceeds of $290.5 million from the sale of 14,950,000 of its common units. See "Other Items – Duncan Energy Partners Transactions" within this Item 7 for additional information regarding Duncan Energy Partners.

- § Cash distributions to our partners and noncontrolling interest increased $137.9 million year-to-year primarily due to an increase in common units outstanding and our quarterly cash distribution rates.

- § We received $48.9 million from the settlement of treasury lock financial instruments during 2007 related to our interest rate risk hedging activities.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our 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 such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, Barnett Shale in North Texas, and the deepwater Gulf of Mexico.

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 thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Capital spending for business combinations:			
Great Divide Gathering System acquisition	$ 125,175	$ --	$ --
Encinal acquisition, excluding non-cash consideration (1)	--	114	145,197
Piceance Basin Gathering System acquisition	--	368	100,000
South Monco Pipeline System acquisition	1	35,000	--
Canadian Enterprise Gas Products, Ltd. acquisition	--	--	17,690
Additional ownership interests in Dixie	57,089	311	12,913
Additional ownership interests in Belle Rose NGL Pipeline, LLC	1,200	--	--
Additional ownership interests in Tri-States	18,695	--	--
Other business combinations	--	--	700
Total	202,160	35,793	276,500
Capital spending for property, plant and equipment, net: (2)			
Growth capital projects (3)	1,773,000	1,986,157	1,148,123
Sustaining capital projects (4)	180,676	142,096	132,455
Total	1,953,676	2,128,253	1,280,578
Capital spending for intangible assets:			
Acquisition of intangible assets (5)	5,126	11,232	--
Capital spending attributable to unconsolidated affiliates:			
Investments in unconsolidated affiliates (6)	129,816	332,909	138,266
Total capital spending	$ 2,290,778	$ 2,508,187	$ 1,695,344

(1) Excludes $181.1 million of non-cash consideration paid to the seller in the form of 7,115,844 of our common units. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for additional information regarding our business combinations.

(2) 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 $25.8 million, $57.5 million and $60.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(3) 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.

(4) 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.

(5) Amount for 2008 represents the acquisition of permits for our Mont Belvieu storage facility. Amount for 2007 represents the acquisition of nitric oxide credits at our Morgan's Point Facility.

(6) Fiscal 2007 includes $216.5 million in cash contributions to Cameron Highway to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for 2009 will approximate $1.00 billion, which includes estimated expenditures of $820.0 million for growth capital projects and acquisitions and $180.0 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, 2008, we had approximately $521.3 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction of our Barnett Shale natural gas pipeline projects and Meeker natural gas processing plant expansion.

Significant Ongoing Growth Capital Projects

The following table summarizes information regarding certain ongoing significant announced growth capital projects (dollars in millions). Actual costs noted for each project reflects our share of cash expenditures as of December 31, 2008, excluding capitalized interest. The current forecast amount noted for each project also reflects our share of project expenditures, excluding estimated capitalized interest.

Project Name	Estimated Date of Completion	Actual Costs	Current Forecast Total Cost
Sherman Extension Pipeline (Barnett Shale)	2009	$ 457.0	$ 489.2
Shenzi Oil Pipeline	2009	135.8	153.5
Marathon Piceance Basin pipeline projects	2009	36.6	151.3
Trinity River Basin Extension	2009	16.4	232.6
Expansion of Wilson natural gas storage facility	2010	51.1	119.6
Texas Offshore Port System	To be determined	30.0	600.0

Sherman Extension Pipeline (Barnett Shale). In November 2006, we announced an expansion of our Texas Intrastate System with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. The Sherman Extension is supported by long-term contracts with Devon Energy Corporation, the largest producer in the Barnett Shale area, and significant indications of interest from leading producers and gatherers in the Fort Worth basin, as well as other shippers on our Texas Intrastate Pipeline system. At its terminus, the new pipeline system will make deliveries into Boardwalk Pipeline Partners L.P.'s Gulf Crossing Expansion Project, which will provide export capacity for Barnett Shale natural gas production to multiple delivery points in Louisiana, Mississippi and Alabama that offer access to attractive markets in the Northeast and Southeast United States. In addition, the Sherman Extension will provide natural gas producers in East Texas and the Waha area of West Texas with access to these higher value markets through our Texas Intrastate Pipeline system. The Sherman Extension will originate near Morgan Mill, Texas and extend through the center of the current Barnett Shale development area to Sherman, Texas. In 2008, we placed into service portions of the Sherman Extension. The Sherman Extension is scheduled for final completion in March 2009.

The Barnett Shale is considered to be one of the largest unconventional natural gas resource plays in North America, covering approximately 14 counties and over seven million acres in the Fort Worth basin in North Texas. Current natural gas production is estimated at 3.4 Bcf/d from approximately 7,800 wells. Approximately 190 rigs are currently estimated to be working to develop Barnett Shale acreage in the region. According to the United States Geological Survey, the Barnett Shale has the resource potential of approximately 26 trillion cubic feet of natural gas.

Shenzi Oil Pipeline. In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm 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 export pipeline will originate at the Shenzi Field, located in 4,300 feet of water at Green Canyon Block 653, approximately 120 miles off the coast of Louisiana. The 83-mile, 20-inch diameter pipeline will have the capacity to transport up to 230 MBPD of crude oil and will connect the Shenzi Field to our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B junction platform. We own a 50.0% interest in the Cameron Highway Oil Pipeline and a 36.0% interest in the Poseidon Oil Pipeline System and operate both pipelines. The Shenzi oil export pipeline will connect to a platform being constructed by BHP Billiton Plc to develop the Shenzi Field, which is expected to commence operations during the second quarter of 2009.

Marathon Piceance Basin pipeline projects. In December 2006, we entered into a long-term contract with Marathon Oil Company ("Marathon") to provide a range of midstream energy services, including natural gas gathering, compression, treating and processing, for Marathon's natural gas production in the Piceance Basin of northwest Colorado. Under the terms of the contract, we are constructing 50 miles of gathering lines and related assets to connect Marathon's multi-well drilling sites, production from which is expected to peak at approximately 180 MMcf/d, to our Piceance Creek Gathering System. From there the natural gas will be delivered to our Meeker natural gas processing facility.

Trinity River Basin Extension. In August 2008, we announced the development of a new 40-mile supply lateral that will extend from the Trinity River Basin north of Arlington, Texas to an interconnect with the Sherman Extension pipeline near Justin, Texas to accommodate growing natural gas production from the Barnett Shale. This new pipeline will consist of 30-inch and 36-inch diameter pipeline designed to provide up to 1.0 Bcf/d of natural gas takeaway capacity for producers in Tarrant and Denton counties. This new pipeline will also have a lateral to provide transportation services for natural gas produced from the Newark East field in Wise County. These new pipeline laterals are anchored by long-term agreements with major producers and are expected to be in-service by year end 2009.

Expansion of Wilson natural gas storage facility. We are developing a new natural gas storage cavern located on the Boling Salt Dome near Boling, Texas. The cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the Texas Railroad Commission and is projected to commence operations in 2010. We expect to secure binding precedent agreements on all capacity before the cavern commences operations.

Texas Offshore Port System (TOPS and PACE). In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. For additional information regarding this joint venture and its capital projects, see "Recent Developments – Texas Offshore Port System" within this Item 7.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL 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 and 2006, we recovered $31.1 million and $13.7 million, respectively from El Paso related to our 2006 and 2005 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 thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Expensed	$ 48,664	$ 43,499	$ 26,397
Capitalized	63,976	52,420	38,180
Total	$ 112,640	$ 95,919	$ 64,577

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $107.0 million in 2009.

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, 2008 and 2007, the net book value of our property, plant and equipment was $13.15 billion and $11.59 billion, respectively. We recorded $466.1 million, $414.9 million, and $350.8 million in depreciation expense for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

Measuring recoverability of long-lived assets and equity method investments

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

We recognized a non-cash asset impairment charge related to property, plant and equipment of $0.1 million in 2006, 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. Similarly, during the year ended December 31, 2006, we evaluated our equity method investment in Neptune for impairment and recorded a $7.4 million non-cash impairment charge. During 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 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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 the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with business combinations and asset purchases. The value we assigned to these customer relationships is being amortized to earnings 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 based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors.

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. 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, etc.);

§ any legal or regulatory developments that would impact such contractual rights; and

§ any contractual provisions that enable us to renew or extend such agreements.

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

At December 31, 2008 and 2007, the carrying value of our intangible asset portfolio was $855.4 million and $917.0 million, respectively. We recorded $88.4 million, $89.7 million, and $88.8 million in amortization expense associated with our intangible assets for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our intangible assets, see Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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 (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

§ discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;

§ long-term growth rates for cash flows beyond the discrete forecast period; and

§ appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2008 and 2007, the carrying value of our goodwill was $706.9 million and $591.7 million, respectively. We did not record any goodwill impairment charges during the periods presented.

For additional information regarding our goodwill, see Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

Our revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our 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). We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of certain estimates for 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 timing to compile actual billing information and receiving 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 the subject 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, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month.

If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods. On an ongoing basis, we review our estimates based on currently available information. Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying notes.

Reserves for environmental matters

Each of our business segments is subject to 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, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

At December 31, 2008 and 2007, we had a liability for environmental remediation of $15.4 million and $26.5 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of American Institute of Certified Public Accountants Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities. See Item 3 of our annual report for recent developments regarding environmental matters.

Natural gas imbalances

In the 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 on-going 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 is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our imbalance receivables, net of allowance for doubtful accounts, were $48.4 million and $60.9 million, respectively, and are reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheets included in this Current Report on Form 8-K. At December 31, 2008 and 2007, our imbalance payables were $40.7 million and $38.3 million, respectively, and are reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets included in this Current Report on Form 8-K.

Other Items

Duncan Energy Partners Transactions

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 of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of 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 the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, 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. ("DEP OLP"), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74.1% of Duncan Energy Partners' limited partner interests and 100.0% of its general partner.

DEP I Midstream Businesses. On February 5, 2007, EPO contributed a 66.0% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets. EPO retained the remaining 34.0% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene'), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL").

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its revolving credit facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 of the Notes to Consolidated Financial Statements included under

Item 8 of this Current Report on Form 8-K for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses. On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the “DEP II Purchase Agreement”) with EPO and Enterprise GTM Holdings L.P. (“Enterprise GTM,” a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100.0% of the membership interests in Enterprise Holding III, LLC (“Enterprise III”) from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% membership interest in Enterprise Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the “DEP II Midstream Businesses.” EPO was the sponsor of this second dropdown transaction. Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a term loan. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

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. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damages 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.

For windstorm events such as hurricanes and tropical storms, EPCO’s deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO’s deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $47.9 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

See Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for more information regarding insurance matters.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2008 (dollars in thousands).

		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)	$ 9,046,046	$ --	$ 1,488,250	$ 2,267,596	$ 5,290,200
Estimated cash payments for interest (2)	$ 9,351,928	$ 544,658	$ 993,886	$ 821,123	$ 6,992,261
Operating lease obligations (3)	$ 331,419	$ 32,299	$ 55,372	$ 51,547	$ 192,201
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 5,225,141	$ 323,309	$ 1,150,102	$ 1,148,610	$ 2,603,120
NGLs	$ 1,923,792	$ 969,870	$ 272,672	$ 272,500	$ 408,750
Petrochemicals	$ 1,746,138	$ 685,643	$ 624,393	$ 268,418	$ 167,684
Other	$ 37,455	$ 19,202	$ 6,781	$ 5,970	$ 5,502
Underlying major volume commitments:					
Natural gas (in BBtus)	981,955	56,650	209,075	214,730	501,500
NGLs (in MBbls)	56,622	23,576	9,446	9,440	14,160
Petrochemicals (in MBbls)	67,696	24,949	23,848	11,665	7,234
Service payment commitments	$ 529,402	$ 52,614	$ 100,403	$ 93,167	$ 283,218
Capital expenditure commitments (5)	$ 521,262	$ 521,262	$ --	$ --	$ --
Other long-term liabilities, as reflected in our Consolidated Balance Sheet (6)	$ 81,277	$ --	$ 14,710	$ 7,573	$ 58,994
Total	$ 28,793,860	$ 3,148,857	$ 4,706,569	$ 4,936,504	$ 16,001,930

(1) Represents our scheduled future maturities of consolidated debt obligations for the periods indicated. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for information regarding our debt obligations.

(2) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at December 31, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2008. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for information regarding variable interest rates charged in 2008 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements in place at December 31, 2008. See Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $550.0 million Junior Notes A (due August 2066) and $682.7 million Junior Notes B (due January 2068). Our estimated cash payments for interest assume that the Junior Note obligations are not called prior to maturity.

(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, (iii) a railcar unloading terminal in Mont Belvieu, Texas, and (iv) land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services based on the contractual terms of each agreement at December 31, 2008.

(5) Represents our short-term unconditional payment obligations relating to our capital projects.

(6) As presented on our Consolidated Balance Sheet at December 31, 2008, other long-term liabilities consist primarily of (i) liabilities for our asset retirement obligations and (ii) liabilities for environmental remediation costs. For information regarding our environmental remediation costs and asset retirement obligations, see Notes 2 and 10 respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

For additional information regarding our significant contractual obligations involving operating leases and purchase obligations, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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 condition, 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, 2008, Poseidon's debt obligations consisted of $109.0 million outstanding under its $150.0 million revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets.

Evangeline. At December 31, 2008, Evangeline's debt obligations consisted of (i) $8.2 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. Duncan Energy Partners had $1.0 million of letters of credit outstanding on December 31, 2008 that were furnished on behalf of Evangeline's debt.

Summary of Related Party Transactions

The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For the Year Ended December 31,		
	2008	2007	2006
Revenues from consolidated operations			
EPCO and affiliates	$ 121,201	$ 67,635	$ 98,671
Energy Transfer Equity and subsidiaries	618,370	294,441	--
Unconsolidated affiliates	396,879	290,640	304,559
Total	$ 1,136,450	$ 652,716	$ 403,230
Cost of sales			
EPCO and affiliates	$ 59,173	$ 33,827	$ 86,050
Energy Transfer Equity and subsidiaries	173,875	26,889	--
Unconsolidated affiliates	90,836	41,474	42,166
Total	$ 323,884	$ 102,190	$ 128,216
Operating costs and expenses			
EPCO and affiliates	$ 314,612	$ 260,716	$ 225,487
Energy Transfer Equity and subsidiaries	18,284	8,267	--
Unconsolidated affiliates	(10,388)	(8,709)	(10,560)
Total	$ 322,508	$ 260,274	$ 214,927
General and administrative expenses			
EPCO and affiliates	$ 59,058	$ 56,518	$ 41,265
Unconsolidated affiliates	(51)	--	--
Total	$ 59,007	$ 56,518	$ 41,265
Other income (expense)			
EPCO and affiliates	$ (274)	$ (170)	$ 680
Unconsolidated affiliates	--	--	262
Total	$ (274)	$ (170)	$ 942

For additional information regarding our related party transactions, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K. For information regarding certain business relationships and related transactions, see Item 13 of our annual report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement (the "ASA") and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities. Enterprise GP Holdings acquired noncontrolling ownership interests in both ETE GP and Energy Transfer Equity in May 2007. As a result of this transaction, ETE GP and Energy Transfer Equity became related parties to us.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments we make to K/D/S Promix, L.L.C. for NGL transportation, storage and fractionation services and to Jonah for natural gas purchases.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see "Other Items – Duncan Energy Partners Transactions" within this section.

Non-GAAP Reconciliations

The following table presents a reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes and the cumulative effect of change in accounting principle (dollars in thousands):

	For the Year the Ended December 31,		
	2008	2007	2006
Total segment gross operating margin	$ 2,057,469	$ 1,492,068	$ 1,362,449
Adjustments to reconcile total gross operating margin			
to operating income:			
Depreciation, amortization and accretion in			
operating costs and expenses	(555,370)	(513,840)	(440,256)
Operating lease expense paid by EPCO	(2,038)	(2,105)	(2,109)
Gain (loss) from asset sales and related transactions in			
operating costs and expenses	3,735	(5,391)	3,359
General and administrative costs	(90,550)	(87,695)	(63,391)
Operating income	1,413,246	883,037	860,052
Other expense, net	(391,448)	(303,463)	(229,967)
Income before provision for income taxes and the			
cumulative effect of change in accounting principle	$ 1,021,798	$ 579,574	$ 630,085

EPCO subleases to us 100 railcars for $1 per year (the "retained leases"). These subleases are part of the ASA that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. For additional information regarding the ASA and the retained leases, see Item 13 of our annual report.

Recent Accounting Pronouncements

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements:

§ SFAS 141(R), Business Combinations;

§ FASB Staff Position SFAS 142-3, Determination of the Useful Life of Intangible Assets;

§ SFAS 157, Fair Value Measurements;

§ SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51;

§ SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133;

§ Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations; and

§ EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to Master Limited Partnerships.

For additional information regarding recent accounting pronouncements, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K.

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

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

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

The following table presents gains (losses) recorded in net income attributable to our interest rate risk and commodity risk hedging transactions for the periods indicated (dollars in thousands). These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Interest Rate Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net	$ 4,409	$ 5,429	$ 4,234
Other gains (losses) from derivative transactions	5,340	(8,934)	(5,195)
Duncan Energy Partners:			
Ineffective portion of cash flow hedges	(5)	(155)	--
Reclassification of cash flow hedge amounts from AOCI, net	(2,008)	350	--
Total hedging gains (losses), net, in consolidated interest expense	$ 7,736	$ (3,310)	$ (961)
Commodity Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net - natural gas marketing activities	$ (30,175)	$ (3,299)	$ (1,327)
Reclassification of cash flow hedge amounts from AOCI, net - NGL and petrochemical operations	(28,232)	(4,564)	13,891
Other gains (losses) from derivative transactions	29,772	(20,712)	(2,307)
Total hedging gains (losses), net, in consolidated operating costs and expenses	$ (28,635)	$ (28,575)	$ 10,257

The following table provides additional information regarding derivative instruments as presented in our Consolidated Balance Sheets at the dates indicated (dollars in thousands):

	At December 31,	
	2008	2007
Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$ 7,780	$ --
Commodity risk hedging portfolio	185,762	341
Foreign currency risk hedging portfolio	9,284	1,308
Total derivative assets – current	$ 202,826	$ 1,649
Other assets:		
Interest rate risk hedging portfolio	$ 38,939	$ 14,744
Total derivative assets – long-term	$ 38,939	$ 14,744
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$ 5,910	$ 22,209
Commodity risk hedging portfolio	281,142	19,575
Foreign currency risk hedging portfolio	109	27
Total derivative liabilities – current	$ 287,161	$ 41,811
Other liabilities:		
Interest rate risk hedging portfolio	$ 3,889	$ 3,080
Commodity risk hedging portfolio	233	--
Total derivative liabilities – long-term	$ 4,122	$ 3,080

The following table presents gains (losses) recorded in other comprehensive income (loss) for cash flow hedges associated with our interest rate risk, commodity risk and foreign currency risk hedging portfolios (dollars in thousands). These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
EPO:			
Gains (losses) on cash flow hedges	$ (20,772)	$ 17,996	$ 11,196
Reclassification of cash flow hedge amounts to net income, net	(4,409)	(5,429)	(4,234)
Duncan Energy Partners:			
Losses on cash flow hedges	(7,989)	(3,271)	--
Reclassification of cash flow hedge amounts to net income, net	2,008	(350)	--
Total interest rate risk hedging gains (losses), net	(31,162)	8,946	6,962
Commodity Risk Hedging Portfolio:			
EPO:			
Natural gas marketing activities:			
Losses on cash flow hedges	(30,642)	(3,125)	(1,034)
Reclassification of cash flow hedge amounts to net income, net	30,175	3,299	1,327
NGL and petrochemical operations:			
Gains (losses) on cash flow hedges	(120,223)	(22,735)	9,976
Reclassification of cash flow hedge amounts to net income, net	28,232	4,564	(13,891)
Total commodity risk hedging gains (losses), net	(92,458)	(17,997)	(3,622)
Foreign Currency Risk Hedging Portfolio:			
Gains on cash flow hedges	9,286	1,308	--
Total foreign currency risk hedging gains (losses), net	9,286	1,308	--
Total cash flow hedge amounts in other comprehensive income (loss) (1)	$ (114,334)	$ (7,743)	$ 3,340

(1) Total cash flow hedge amounts in other comprehensive income (loss) include amounts attributable to noncontrolling interest. Such amounts were $1.9 million (loss) and $2.6 million (loss) for the years ended December 31, 2008 and 2007, respectively.

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded in net income and other comprehensive income and on our balance sheet related to our consolidated hedging activities, please refer to the preceding tables.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – EPO interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, we had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $12.9 million (an asset).

The following table summarizes our interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in millions).

Scenario	Resulting Classification	Swap Fair Value at December 31, 2007	Swap Fair Value at December 31, 2008	Swap Fair Value at February 3, 2009
FV assuming no change in underlying interest rates	*Asset*	$ 12.9	$ 46.7	$ 36.3
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(7.4)	42.4	31.1
FV assuming 10% decrease in underlying interest rates	*Asset*	33.1	51.1	41.5

The fair value of the interest rate swaps excludes related hedged amounts we have recorded in earnings. The change in fair value between December 31, 2008 and February 3, 2009 is primarily due to an increase in market interest rates relative to the interest rates used to determine the fair value of our financial instruments at December 31, 2008. The underlying floating LIBOR forward interest rate curve used to determine the February 3, 2009 fair values ranged from approximately 1.3% to 3.8% using 6-month reset periods ranging from February 2008 to March 2014.

Cash flow hedges – EPO treasury locks

We may enter into treasury rate lock transactions ("treasury locks") to hedge U.S. treasury rates related to its anticipated issuances of debt. Each of our treasury lock transactions was designated as a cash flow hedge. Gains or losses on the termination of such instruments are reclassified into net income (as a component of interest expense) using the effective interest method over the estimated term of the underlying fixed-rate debt. At December 31, 2008, we had no treasury lock financial instruments outstanding. At December 31, 2007, the aggregate notional value of our treasury lock financial instruments was $600.0 million, which had a total fair value (a liability) of $19.6 million. We terminated a number of treasury lock financial instruments during 2008 and 2007. These terminations resulted in realized losses of $40.4 million in 2008 and gains of $48.8 million in 2007.

We expect to reclassify $1.6 million of cumulative net gains from our interest rate risk cash flow hedges into net income (as a decrease to interest expense) during 2009.

Cash flow hedges – Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 and 2007 was a liability of $9.8 million and $3.8 million, respectively. Duncan Energy Partners expects to reclassify $6.0 million of cumulative net losses from its interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009.

The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded in other comprehensive income (loss) and amortized into earnings based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of Duncan Energy Partners' interest rate swap portfolio (dollars in millions).

		Swap Fair Value at		
Scenario	Resulting Classification	December 31, 2007	December 31, 2008	February 3, 2009
FV assuming no change in underlying interest rates	*Liability*	$ (3.8)	$ (9.8)	$ (9.4)
FV assuming 10% increase in underlying interest rates	*Liability*	(2.2)	(9.4)	(9.0)
FV assuming 10% decrease in underlying interest rates	*Liability*	(5.3)	(10.2)	(9.8)

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas prices during the second half of 2008. As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity financial instruments we utilize are settled in cash.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with its NGL and petrochemical operations.

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million and a liability of $0.3 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008**	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (0.3)	$ 6.5	$ 13.9
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(1.4)	2.7	9.4
FV assuming 10% decrease in underlying commodity prices	*Asset*	0.7	9.9	18.3

The change in fair value of the instruments between December 31, 2008 and February 3, 2009 is primarily due to a decrease in natural gas prices.

NGL and petrochemical operations

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million and $19.0 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting. We expect to reclassify $114.0 million of cumulative net losses from these cash flow hedges into net income (as an increase in operating costs and expenses) during 2009.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity financial instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as financial instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income (loss). Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity financial instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the financial instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount it originally hedged under this program.

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008**	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Liability*	$ (19.0)	$ (102.1)	$ (111.6)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	11.3	(94.0)	(109.2)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(49.2)	(110.1)	(114.1)

The change in fair value of the NGL and petrochemical portfolio between December 31, 2008 and February 3, 2009 is primarily due to a decrease in natural gas prices.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the year ended December 31, 2008, we recorded minimal gains from these financial instruments.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement ("Yen Term Loan") that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan. Total interest expense under this loan agreement was $4.0 million, of which $1.7 million is the expected foreign currency loss, which will be recorded as interest expense.

Product Purchase Commitments

We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas 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 Current Report on Form 8-K.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for information regarding fair value disclosures pertaining to our financial assets and liabilities.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) 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 accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated (dollars in thousands):

	At December 31,	
	2008	**2007**
Commodity financial instruments (1)	$ (114,077)	$ (21,619)
Interest rate financial instruments (1)	3,818	34,980
Foreign currency cash flow hedges (1)	10,594	1,308
Foreign currency translation adjustment (2)	(1,301)	1,200
Pension and postretirement benefit plans (3)	(751)	588
Subtotal	(101,717)	16,457
Amount attributable to noncontrolling interest (4)	4,520	2,603
Total accumulated other comprehensive income (loss) in partners' equity	$ (97,197)	$ 19,060

(1) See Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this Current Report on Form 8-K for additional information regarding pension and postretirement benefit plans.
(4) Represents the amount of accumulated other comprehensive loss allocated to noncontrolling interest based on the provisions of SFAS 160.

The following table summarizes the components of other comprehensive income (loss) for the periods indicated, prior to attributing amounts to noncontrolling interest (dollars in thousands):

	For Year Ended December 31,		
	2008	2007	2006
Other comprehensive income (loss):			
Cash flow hedges	$ (114,334)	$ (7,743)	$ 3,340
Change in funded status of pension and postretirement plans, net of tax	(1,339)	(52)	--
Foreign currency translation adjustment	(2,501)	2,007	(807)
Total other comprehensive income (loss)	$ (118,174)	$ (5,788)	$ 2,533

Item 8.   Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2008 and 2007, 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, 2008. 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 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 Products Partners L.P. and subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 3 to the consolidated financial statements, the accompanying consolidated financial statements have been retrospectively adjusted for the adoption of FASB Statement No. 160, "*Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51"* ("SFAS 160") and Emerging Issues Task Force 07-4, "*Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships"* ("EITF 07-4").

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, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2009 (not presented herein) expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 2, 2009
(July 6, 2009 as to the effects of the adoption of SFAS 160 and EITF 07-4 and the related disclosures in Notes 1 and 3)

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31,	
ASSETS	**2008**	**2007**
Current assets:		
Cash and cash equivalents	$ 35,373	$ 39,722
Restricted cash	203,789	53,144
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $15,123 at December 31, 2008 and $21,659 at December 31, 2007	1,185,515	1,930,762
Accounts receivable – related parties	61,629	79,782
Inventories	362,815	354,282
Derivative assets	202,826	1,649
Prepaid and other current assets	111,773	78,544
Total current assets	2,163,720	2,537,885
Property, plant and equipment, net	13,154,774	11,587,264
Investments in and advances to unconsolidated affiliates	949,526	858,339
Intangible assets, net of accumulated amortization of $429,872 at December 31, 2008 and $341,494 at December 31, 2007	855,416	917,000
Goodwill	706,884	591,652
Deferred tax asset	355	3,522
Other assets, including restricted cash of $17,871 at December 31, 2007	126,860	112,345
Total assets	$ 17,957,535	$ 16,608,007
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 300,532	$ 324,999
Accounts payable – related parties	39,558	24,432
Accrued product payables	1,142,370	2,227,489
Accrued expenses	48,772	47,756
Accrued interest	151,873	130,971
Derivative liabilities	287,161	41,811
Other current liabilities	252,883	247,225
Total current liabilities	2,223,149	3,044,683
Long-term debt: (see Note 14)		
Senior debt obligations – principal	7,813,346	5,646,500
Junior subordinated notes – principal	1,232,700	1,250,000
Other	62,364	9,645
Total long-term debt	9,108,410	6,906,145
Deferred tax liabilities	66,062	21,364
Other long-term liabilities	81,277	73,748
Commitments and contingencies		
Equity: (see Note 15)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (439,354,731 units outstanding at December 31, 2008 and 433,608,763 units outstanding at December 31, 2007)	6,036,887	5,976,947
Restricted common units (2,080,600 units outstanding at December 31, 2008 and 1,688,540 units outstanding at December 31, 2007)	26,219	15,948
General partner	123,599	122,297
Accumulated other comprehensive income (loss)	(97,197)	19,060
Total Enterprise Products Partners L.P. partners' equity	6,089,508	6,134,252
Noncontrolling interest	389,129	427,815
Total equity	6,478,637	6,562,067
Total liabilities and equity	$ 17,957,535	$ 16,608,007

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31,		
	2008	2007	2006
Revenues:			
Third parties	$ 20,769,206	$ 16,297,409	$ 13,587,739
Related parties	1,136,450	652,716	403,230
Total revenues (see Note 16)	21,905,656	16,950,125	13,990,969
Costs and expenses:			
Operating costs and expenses:			
Third parties	19,814,572	15,646,587	12,745,948
Related parties	646,392	362,464	343,143
Total operating costs and expenses	20,460,964	16,009,051	13,089,091
General and administrative costs:			
Third parties	31,543	31,177	22,126
Related parties	59,007	56,518	41,265
Total general and administrative costs	90,550	87,695	63,391
Total costs and expenses	20,551,514	16,096,746	13,152,482
Equity in earnings of unconsolidated affiliates	59,104	29,658	21,565
Operating income	1,413,246	883,037	860,052
Other income (expense):			
Interest expense	(400,686)	(311,764)	(238,023)
Interest income	5,523	8,601	7,589
Other, net	3,715	(300)	467
Total other expense, net	(391,448)	(303,463)	(229,967)
Income before provision for income taxes and the cumulative effect of change in accounting principle	1,021,798	579,574	630,085
Provision for income taxes	(26,401)	(15,257)	(21,323)
Income before the cumulative effect of change in accounting principle	995,397	564,317	608,762
Cumulative effect of change in accounting principle (see Note 8)	--	--	1,472
Net income	995,397	564,317	610,234
Net income attributable to noncontrolling interest	(41,376)	(30,643)	(9,079)
Net income attributable to Enterprise Products Partners L.P.	$ 954,021	$ 533,674	$ 601,155
Net income allocated to: (see Note 15)			
Limited partners	$ 811,547	$ 417,728	$ 504,156
General partner	$ 142,474	$ 115,946	$ 96,999
Earnings per unit: (see Note 19)			
Basic and diluted earnings per unit before change in accounting principle	$ 1.84	$ 0.95	$ 1.20
Basic and diluted earnings per unit	$ 1.84	$ 0.95	$ 1.20

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2008	2007	2006
Net income	$ 995,397	$ 564,317	$ 610,234
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity financial instrument gains (losses) during period	(150,865)	(25,860)	8,942
Reclassification adjustment for (gains) losses included in net income related to commodity financial instruments	58,407	7,863	(12,564)
Interest rate financial instrument gains (losses) during period	(28,761)	14,725	11,196
Reclassification adjustment for gains included in net income related to interest rate financial instruments	(2,401)	(5,779)	(4,234)
Foreign currency hedge gains	9,286	1,308	--
Total cash flow hedges	(114,334)	(7,743)	3,340
Foreign currency translation adjustment	(2,501)	2,007	(807)
Change in funded status of pension and postretirement plans, net of tax	(1,339)	(52)	--
Total other comprehensive income (loss)	(118,174)	(5,788)	2,533
Comprehensive income	877,223	558,529	612,767
Comprehensive income attributable to noncontrolling interest	39,459	28,040	9,079
Comprehensive income attributable to Enterprise Products Partners L.P.	$ 837,764	$ 530,489	$ 603,688

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31,		
	2008	2007	2006
Operating activities:			
Net income	$ 995,397	$ 564,317	$ 610,234
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion in operating costs and expenses	555,370	513,840	440,256
Depreciation and amortization in general and administrative costs	10,659	10,258	7,186
Amortization in interest expense	(3,858)	(336)	766
Equity in earnings of unconsolidated affiliates	(59,104)	(29,658)	(21,565)
Distributions received from unconsolidated affiliates	98,553	73,593	43,032
Provision for impairment of long-lived asset	--	--	88
Cumulative effect of change in accounting principle	--	--	(1,472)
Operating lease expense paid by EPCO, Inc.	2,038	2,105	2,109
Loss (gain) from asset sales and related transactions	(3,746)	5,391	(3,359)
Loss (gain) on early extinguishment of debt	(7,093)	250	--
Deferred income tax expense	6,199	8,306	14,427
Changes in fair market value of financial instruments	198	981	(51)
Effect of pension settlement recognition	(114)	588	--
Net effect of changes in operating accounts (see Note 22)	(357,430)	441,306	83,418
Net cash flows provided by operating activities	1,237,069	1,590,941	1,175,069
Investing activities:			
Capital expenditures	(1,979,459)	(2,185,800)	(1,341,070)
Contributions in aid of construction costs	25,783	57,547	60,492
Proceeds from asset sales and related transactions	15,999	12,027	3,927
Increase in restricted cash	(132,775)	(47,347)	(8,715)
Cash used for business combinations (see Note 12)	(202,160)	(35,793)	(276,500)
Acquisition of intangible assets	(5,126)	(11,232)	--
Investments in unconsolidated affiliates	(129,816)	(332,909)	(138,266)
Advances from (to) unconsolidated affiliates	(4,315)	(10,100)	10,844
Cash used in investing activities	(2,411,869)	(2,553,607)	(1,689,288)
Financing activities:			
Borrowings under debt agreements	8,683,450	6,024,518	3,378,285
Repayments of debt	(6,528,126)	(4,458,141)	(2,907,000)
Debt issuance costs	(17,584)	(16,511)	(8,955)
Distributions paid to partners	(1,037,373)	(957,705)	(843,292)
Distributions paid to noncontrolling interest	(55,851)	(32,326)	(8,831)
Proceeds from initial public offering of Duncan Energy Partners in noncontrolling interest (see Notes 2 and 17)	--	290,466	--
Other contributions from noncontrolling interest	28	12,506	27,578
Net proceeds from issuance of common units	142,777	69,221	857,187
Repurchase of restricted option awards	--	(1,568)	--
Acquisition of treasury units	(1,911)	--	--
Monetization of interest rate hedging financial instruments (see Note 7)	(14,444)	48,895	--
Cash provided by financing activities	1,170,966	979,355	494,972
Effect of exchange rate changes on cash	(515)	414	(232)
Net change in cash and cash equivalents	(3,834)	16,689	(19,247)
Cash and cash equivalents, January 1	39,722	22,619	42,098
Cash and cash equivalents, December 31	$ 35,373	$ 39,722	$ 22,619

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 15 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss))
(Dollars in thousands)

	Enterprise Products Partners L.P.					
	Limited Partners	General Partner	Deferred Compensation	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2005	$ 5,561,338	$ 113,496	$ (14,597)	$ 19,072	$ 103,168	5,782,477
Net income	504,156	96,999	--	--	9,079	610,234
Operating leases paid by EPCO, Inc.	2,067	42	--	--	--	2,109
Cash distributions to partners	(739,632)	(101,805)	--	--	--	(841,437)
Unit option reimbursements to EPCO, Inc.	(1,818)	(41)	--	--	--	(1,859)
Cash distributions to noncontrolling interest	--	--	--	--	(8,831)	(8,831)
Net proceeds from issuance of common units	830,825	16,943	--	--	--	847,768
Common units issued to Lewis in connection with Encinal acquisition	181,112	3,705	--	--	--	184,817
Proceeds from exercise of unit options	5,601	114	--	--	--	5,715
Contributions from noncontrolling interest	--	--	--	--	27,578	27,578
Change in accounting method for equity awards (see Note 8)	(15,815)	(307)	14,597	--		(1,525)
Amortization of equity awards	8,282	155	--	--		8,437
Acquisition of additional interest in subsidiary	--	--	--	--	(1,865)	(1,865)
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(464)	--	(464)
Foreign currency translation adjustment	--	--	--	(807)	--	(807)
Acquisition-related disbursement of cash	(6,199)	(126)	--	--	--	(6,325)
Cash flow hedges	--	--	--	3,340	--	3,340
Balance, December 31, 2006	6,329,917	129,175	--	21,141	129,129	6,609,362
Net income	417,728	115,946	--	--	30,643	564,317
Operating leases paid by EPCO, Inc.	2,063	42	--	--	--	2,105
Cash distributions to partners	(833,793)	(124,388)	--	--	--	(958,181)
Unit option reimbursements to EPCO, Inc.	(2,999)	(58)	--	--	--	(3,057)
Cash distributions to noncontrolling interest	--	--	--	--	(32,326)	(32,326)
Net proceeds from issuance of common units	60,445	1,232	--	--	--	61,677
Proceeds from exercise of unit options	7,549	154	--	--	--	7,703
Contributions from noncontrolling interest	--	--	--	--	302,972	302,972
Repurchase of restricted units and options	(1,568)	--	--	--	--	(1,568)
Amortization of equity awards	13,553	194	--	--	--	13,747
Change in funded status of pension and postretirement plans, net of tax	--	--	--	1,063	(11)	1,052
Foreign currency translation adjustment	--	--	--	2,007	--	2,007
Cash flow hedges	--	--	--	(5,151)	(2,592)	(7,743)
Balance, December 31, 2007	5,992,895	122,297	--	19,060	427,815	6,562,067
Net income	811,547	142,474	--	--	41,376	995,397
Operating leases paid by EPCO, Inc.	1,997	41	--	--	--	2,038
Cash distributions to partners	(892,693)	(144,130)	--	--	--	(1,036,823)
Unit option reimbursements to EPCO, Inc.	(550)	--	--	--	--	(550)
Cash distributions to noncontrolling interest	--	--	--	--	(55,851)	(55,851)
Non-cash distributions	(7,140)	(144)	--	--	--	(7,284)
Acquisition of treasury units	(1,873)	(38)	--	--	--	(1,911)
Net proceeds from issuance of common units	139,248	2,842	--	--	--	142,090
Proceeds from exercise of unit options	679	8	--	--	--	687
Contributions from noncontrolling interest	--	--	--	--	28	28
Amortization of equity awards	18,996	249	--	--	--	19,245
Acquisition of additional interest in subsidiaries	--	--	--	--	(22,322)	(22,322)
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(1,350)	11	(1,339)
Foreign currency translation adjustment	--	--	--	(2,501)	--	(2,501)
Cash flow hedges	--	--	--	(112,406)	(1,928)	(114,334)
Balance, December 31, 2008	$ 6,063,106	$ 123,599	$ --	$ (97,197)	$ 389,129	$ 6,478,637

See Notes to Consolidated Financial Statements.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1. Partnership Organization

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

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"), as successor in interest by merger to Enterprise Products Operating L.P. We are owned 98.0% by our limited partners and 2.0% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100.0% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired noncontrolling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

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 private company affiliates of EPCO.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 17). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP Operating Partnership L.P. ("DEP OLP") acquired 100.0% of the membership interests in Enterprise III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, L.P. ("Enterprise GC"), a 51.0% general partner interest in Enterprise Intrastate L.P. ("Enterprise Intrastate") and a 51.0% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction. Enterprise GTM retained the remaining general partner and member interests in the DEP II Midstream Businesses (see Note 17).

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

Effective January 1, 2009, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 and Emerging Issues Task Force ("EITF") 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships. SFAS 160 established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our Consolidated Financial Statements. EITF 07-4 established the manner in which a master limited partnership should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. The presentation and disclosure requirements of SFAS 160 and EITF 07-4 have been applied retrospectively to the Consolidated Financial Statements and Notes included in this Current Report on Form 8-K.

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 the Year Ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 21,659	$ 23,406	$ 37,329
Charges to expense	1,098	2,614	473
Deductions	(7,634)	(4,361)	(14,396)
Balance at end of period	$ 15,123	$ 21,659	$ 23,406

See "Credit Risk Due to Industry Concentrations" in Note 21 for more 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.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows provided by 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, changes in the fair market value of financial instruments and equity in earnings in unconsolidated affiliates 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.

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 material 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.

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 3.0% and 50.0% 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 20.0% and 50.0% and we exercise significant influence over the entity's operating and financial policies. In consolidation we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts are material and remain on our 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. We currently do not have any investments accounted for 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 5.0% 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, 2008 and 2007, deferred revenues totaled $107.8 million and $74.4 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.

Earnings Per Unit

Earnings per unit is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 19 for additional information regarding our earnings per unit.

Employee Benefit Plans

In 2005, we acquired a controlling ownership interest in Dixie Pipeline Company ("Dixie"), which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans.

SFAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of SFAS 87, 88, 106, and 132(R), requires businesses to record the over-funded or under-funded status of defined benefit pension and other postretirement plans as an asset or liability at a measurement date and to recognize annual changes in the funded status of each plan through other comprehensive income (loss). At December 31, 2006, Dixie adopted the provisions of SFAS 158. See Note 6 for additional information regarding Dixie's employee benefit plans.

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, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability for remediation costs associated with mercury gas meters. The balance of this environmental liability was $6.3 million and $17.2 million at December 31, 2008 and 2007, respectively. At December 31, 2008 and 2007, total reserves for environmental liabilities, including those related to the mercury gas meters, were $15.4 million and $26.5 million, respectively. At

December 31, 2008 and 2007, $2.8 million and $6.3 million, respectively, of these amounts are classified as current liabilities.

In February 2007, we reserved $6.5 million in cash we received from a third party to fund anticipated environmental remediation costs. These expected costs are associated with assets acquired in connection with the GulfTerra Merger. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification arrangement was terminated.

The following table presents the activity of our environmental reserves for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 26,459	$ 24,178	$ 22,090
Charges to expense	905	375	1,105
Acquisition-related additions and other	--	6,499	8,811
Deductions	(12,002)	(4,593)	(7,828)
Balance at end of period	$ 15,362	$ 26,459	$ 24,178

Equity Awards

See Note 5 for information regarding our accounting for equity awards.

Estimates

Preparing our financial statements in conformity with generally accepted accounting principles in the United States ("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.

We revised the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System, effective January 1, 2008. This revision adjusted the remaining useful life of such assets to incorporate recent data showing that proved 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 at January 1, 2008. For additional information regarding this change in estimate, see Note 10.

Exchange Contracts

Exchanges are contractual agreements for the movements of 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, and 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.

Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with a business combination or with a disposal activity covered by SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS 146, Accounting for Costs Associated with Exit and Disposal Activities, we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan.

Financial Instruments

We use financial 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. We recognize these transactions as assets or liabilities on our Consolidated Balance Sheets based on the instrument's fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period (i.e., using mark-to-market accounting) unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income (loss), which is generally referred to as "AOCI." Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income (loss) to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings. See Note 8 for additional information regarding our financial instruments.

Foreign Currency Translation

We own a 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 income (loss) 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 7 for information regarding our hedging of currency risk.

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. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 13 for additional information regarding our goodwill.

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 in accordance with SFAS 144. 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.

We recorded a non-cash asset impairment charge of $0.1 million in 2006, which is reflected as a component of operating costs and expenses in our 2006 Statement of Consolidated Operations. No asset impairment charges were recorded in 2008 and 2007.

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 earnings to adjust the carrying value of the investment to its estimated fair value.

During 2007, we evaluated our equity method investment in Nemo Gathering Company, LLC ("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 of unconsolidated affiliates" on our Consolidated Statement of Operations for the year ended December 31, 2007. Similarly, during 2006, we evaluated our investment in Neptune Pipeline Company, L.L.C. ("Neptune") for impairment. As a result of this evaluation, we recorded a $7.4 million non-cash impairment charge that is a component of "Equity in earnings of unconsolidated affiliates" on our Consolidated Statement of Operations for the year ended December 31, 2006. We had no such impairment charges during the year ended December 31, 2008. See Note 11 for additional information regarding our equity method investments.

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, 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.

In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its pre-existing franchise tax, which applied to corporations and limited liability companies, to include limited partnerships and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas changed from non-taxable to taxable.

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.

In accordance with Financial Accounting Standards Board Interpretation 48, Accounting for Uncertainty in Income Taxes, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50.0% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows. See Note 18 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of NGLs, certain petrochemical products and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges directly related to volumes we purchase from third parties or take title to in connection with processing or other agreements. As these volumes are sold and delivered out of inventory, the average cost of these products (including freight-in charges that have been capitalized) 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 9 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 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 on-going 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 is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our natural gas imbalance receivables, net of allowance for doubtful accounts, were $48.4 million and $60.9 million, respectively, and are reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheets. At December 31, 2008 and 2007, our imbalance payables were $40.7 million and $38.3 million, respectively, and are reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets.

Noncontrolling Interest

As presented in our Consolidated Balance Sheets, noncontrolling interest represents third-party and affiliate ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our controlled subsidiaries, including Duncan Energy Partners, are consolidated with those of our own, with any third-party or affiliate ownership in such amounts presented as noncontrolling interest. See Note 15 for information regarding noncontrolling interest.

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, the following: (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 10 for additional information regarding our property, plant and equipment, including a change in depreciation expense beginning January 1, 2008 resulting from a change in the estimated useful life of certain assets.

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 financial instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. At December 31, 2007, restricted cash also included amounts held by a third party trustee responsible for disbursing proceeds from our Petal GO Zone bond offering. During 2008, virtually all proceeds from the Petal GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The following table presents the components of our restricted cash balances at the periods indicated:

	At December 31, 2008	At December 31, 2007
Amounts held in brokerage accounts related to commodity hedging activities and physical natural gas purchases	$ 203,789	$ 53,144
Proceeds from Petal GO Zone bonds reserved for construction costs	1	17,871
Total restricted cash	$ 203,790	$ 71,015

Revenue Recognition

See Note 4 for information regarding our revenue recognition policies.

Start-Up and Organization Costs

Start-up costs and organization costs are expensed as incurred. Start-up costs are defined as one-time activities related to opening a new facility, introducing a new product or service, conducting activities in a new territory, pursuing a new class of customer, initiating a new process in an existing facility or some new operation. Routine ongoing efforts to improve existing facilities, products or services are not considered start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

Note 3. Recent Accounting Developments

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements: SFAS 141(R), Business Combinations; FASB Staff Position ("FSP") SFAS 142-3, Determination of the Useful Life of Intangible Assets; SFAS 157, Fair Value Measurements; SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51; SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133; Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations; and EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to Master Limited Partnerships ("MLPs").

SFAS 141(R), Business Combinations. SFAS 141(R) replaces SFAS 141, Business Combinations and was effective January 1, 2009. SFAS 141(R) retains the fundamental requirements of SFAS 141 in that the acquisition method of accounting (previously termed the "purchase method") be used for all business combinations and for the "acquirer" to be identified in each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. SFAS 141(R) will have an impact on the way in which we evaluate acquisitions.

The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

§ Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.

§ Recognizes and measures any goodwill acquired in the business combination or a gain resulting from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in net income as a gain attributable to the acquirer.

§ Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder's fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price.

FSP FAS 142-3, Determination of the Useful Life of Intangible Assets. FSP 142-3 revised the factors that should be considered in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements.

SFAS 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009. See Note 7 for information regarding fair value-related disclosures required for 2008 in connection with SFAS 157.

SFAS 157 applies to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies are required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51. SFAS 160 established accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior accounting literature. SFAS 160 was effective January 1, 2009. A noncontrolling interest is that portion of equity in a consolidated subsidiary not attributable, directly or indirectly, to a reporting entity. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e., elimination of the "mezzanine" presentation); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income be allocated between the reporting entity and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests.

Effective January 1, 2009, we adopted the provisions of SFAS 160. The presentation and disclosure requirements of SFAS 160 have been applied retrospectively to the Consolidated Financial Statements and Notes included in this Current Report on Form 8-K.

SFAS 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of SFAS 133. SFAS 161 revised the disclosure requirements for financial instruments and related hedging activities to provide users of financial statements with an enhanced understanding of (i) why and how an entity uses financial instruments, (ii) how an entity accounts for financial instruments and related hedged items under SFAS 133, Accounting for Derivative Instruments and Hedging Activities (including related interpretations), and (iii) how financial instruments and related hedged items affect an entity's financial position, financial performance, and cash flows.

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

EITF 08-6, Equity Method Investment Accounting Considerations. EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments under SFAS 141(R) and SFAS 160. EITF 08-6 generally requires that (i) transaction costs should be included in the initial carrying value of an equity method investment; (ii) an equity method investor shall not test separately an investee's underlying assets for impairment, rather such testing should be performed in accordance with Opinion 18 (i.e., on the equity method investment itself); (iii) an equity method investor shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment (any gain or loss to the investor resulting from the investee's share issuance shall be recognized in earnings); and (iv) a gain or loss should not be recognized when changing the method of accounting for an investment from the equity method to the cost method. EITF 08-6 was effective January 1, 2009.

EITF 07-4, Application of the Two Class Method Under SFAS 128, Earnings Per Share, to MLPs. EITF 07-4 prescribes the manner in which a MLP should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. Under the two-class method, current period earnings are allocated to the general partner (including earnings attributable to any embedded incentive distribution rights ("IDRs")) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement.

Effective January 1, 2009, we adopted the provisions of EITF 07-4. The requirements of EITF 07-4 have been applied retrospectively to the Consolidated Financial Statements and Notes included in this Current Report on Form 8-K (see Note 19).

Note 4. 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. The following information provides a general description our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

This aspect of our business generates revenues primarily from the provision of natural gas processing, NGL pipeline transportation, product storage and NGL fractionation services and the sale of NGLs. In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid-contracts (i.e. mixed percent-of-liquids and fee-based) and keepwhole contracts. Under margin-band and keepwhole 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 of NGLs obtained from either our natural gas processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can 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 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.

Revenues from product terminalling activities (applicable to our import and export operations) 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 export 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.

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 (typically in cents per gallon) that is 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.

Onshore Natural Gas Pipelines & Services

This aspect of our business generates revenues primarily from the provision of natural gas pipeline transportation and gathering services; natural gas storage services; and from the sale of natural gas. Certain of our onshore natural gas pipelines generate revenues from transportation and gathering agreements as customers are billed a fee per unit of volume multiplied by the volume delivered or gathered. Fees charged under these arrangements are either contractual or regulated by governmental agencies such as the FERC. Revenues associated with these fee-based contracts are recognized when volumes have been delivered.

Revenues from natural gas storage contracts typically have two components: (i) a monthly demand payment, which is associated with storage capacity reservations, and (ii) a storage fee per unit of volume held at each location. 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 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, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

This aspect of our business generates revenues from the provision of offshore natural gas and crude oil pipeline transportation services and related offshore platform operations. Our offshore natural gas pipelines generate revenues through fee-based contracts or tariffs where revenues are equal to the product of a fee per unit of volume (typically in million British thermal units) multiplied by the volume of natural gas transported. Revenues associated with these fee-based contracts and tariffs are recognized when natural gas volumes have been delivered.

The majority of revenues from our offshore crude oil pipelines are generated based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to long-term transportation agreements with producers. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the level of fees charged to customers.

Revenues from offshore platform services generally consist of demand payments 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 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 payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $54.6 million of demand revenues annually through March 2012. The Marco Polo platform will earn $2.1 million of demand revenues monthly through March 2009.

Petrochemical Services

This aspect of our business generates revenues from the provision of isomerization and propylene fractionation services and the sale of certain petrochemical products. Our isomerization and propylene fractionation operations 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 isomerization operations. Revenues resulting from such agreements are recognized in the period the services are provided.

Our petrochemical marketing activities generate revenues from the sale of propylene and other petrochemicals obtained from either its processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the petrochemicals are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Note 5. Accounting for Equity Awards

We account for equity awards in accordance with SFAS 123(R), Share-Based Payment. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. The fair value of an equity-classified award (such as 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 (such as 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.

As used in the context of the EPCO plans, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to our restricted common units was reversed on January 1, 2006.

Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit I and the issuance of restricted units. The effects of applying SFAS 123(R) during the year ended December 31, 2006 did not have a material effect on our net income or basic and diluted earnings per unit. Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard.

The following table summarizes our equity compensation amounts by plan during each of the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
EPCO 1998 Long-Term Incentive Plan ("EPCO 1998 Plan")			
Unit options	$ 439	$ 4,447	$ 701
Restricted units	8,816	7,721	5,019
Total EPCO 1998 Plan (1)	9,255	12,168	5,720
Enterprise Products 2008 Long-Term Incentive Plan ("EPD 2008 LTIP")			
Unit options	87	--	--
Total EPD 2008 LTIP	87	--	--
Employee Partnerships	5,535	3,911	2,146
DEP GP UARs	1	69	--
Total compensation expense	$ 14,878	$ 16,148	$ 7,866

(1) Amounts for the year ended December 31, 2007 include $4.6 million associated with the resignation of our general partner's former chief executive officer.

EPCO 1998 Plan

Unit option awards. Under the EPCO 1998 Plan, non-qualified incentive options to purchase a fixed number of our common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, we amended the terms of certain of our 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 obligations under the EPCO 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse 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 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 our common units, and expected unit price volatility of our 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 our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

The EPCO 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at December 31, 2008 and the issuance and forfeiture of restricted unit awards through December 31, 2008, a total of 814,674 additional common units could be issued under the EPCO 1998 Plan.

The following table presents option activity under the EPCO 1998 Plan 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, 2005	2,082,000	$ 22.16		
Granted (2)	590,000	24.85		
Exercised	(211,000)	15.95		
Forfeited	(45,000)	24.28		
Outstanding at December 31, 2006	2,416,000	23.32		
Granted (3)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (4)	(740,000)	24.62		
Outstanding at December 31, 2007 (5)	2,315,000	26.18		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008 (6)	2,168,500	26.32	5.19	$ --
Options exercisable at:				
December 31, 2006	591,000	$ 20.85	5.11	$ 4,808
December 31, 2007	335,000	$ 22.06	3.96	$ 3,291
December 31, 2008 (6)	548,500	$ 21.47	4.08	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) The total grant date fair value of these awards was $1.2 million based on the following assumptions: (i) weighted-average expected life of options of seven years; (ii) weighted-average risk-free interest rate of 5.0%; (iii) weighted-average expected distribution yield on our common units of 8.9%; and (iv) weighted-average expected unit price volatility on our common units of 23.5%.
(3) The total grant date fair value of these awards was $2.4 million based on the following assumptions: (i) expected life of options of seven years; (ii) weighted-average risk-free interest rate of 4.8%; (iii) weighted-average expected distribution yield on our common units of 8.4%; and (iv) weighted-average expected unit price volatility on our common units of 23.2%.
(4) Includes the settlement of 710,000 options in connection with the resignation of our general partner’s former chief executive officer.
(5) During 2008, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.
(6) We were committed to issue 2,168,500 and 2,315,000 of our common units at December 31, 2008 and 2007, respectively, if all outstanding options awarded under the EPCO 1998 Plan (as of these dates) were exercised. An additional 365,000, 480,000 and 775,000 of these options are exercisable in 2009, 2010 and 2012, respectively.

The total intrinsic value of option awards exercised during the years ended December 31, 2008, 2007 and 2006 were $0.6 million, $3.0 million and $2.2 million, respectively. At December 31, 2008, there was an estimated $1.7 million of total unrecognized compensation cost related to nonvested unit option awards granted under the EPCO 1998 Plan. We expect to recognize this cost over a weighted-average period of 2.1 years. We will recognize our share of these costs in accordance with the EPCO administrative services agreement (the "ASA") (see Note 17).

During the years ended December 31, 2008 and 2007, we received cash of $0.7 million and $7.5 million, respectively, from the exercise of option awards granted under the EPCO 1998 Plan. Conversely, our option-related reimbursements to EPCO were $0.6 million and $3.0 million, respectively.

Restricted unit awards. Under the EPCO 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. In general, the restricted unit awards allow recipients to acquire the underlying common units at no cost to the recipient once a defined cliff vesting period expires, subject to certain forfeiture provisions. The restrictions on such units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. Fair value of such restricted units is based on the market price of the underlying common units on the date of grant and 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 us to our unitholders. Since restricted units are issued securities, such distributions are reflected as a component of cash distributions to partners as shown on our Statements of Consolidated Cash Flows. We paid $3.9 million, $2.6 million and $1.6 million in cash distributions with respect to restricted units during the years ended December 31, 2008, 2007 and 2006, respectively.

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, 2005	751,604	
Granted (2)	466,400	$ 25.21
Vested	(42,136)	$ 24.02
Forfeited	(70,631)	$ 22.86
Restricted units at December 31, 2006	1,105,237	
Granted (3)	738,040	$ 25.61
Vested	(4,884)	$ 25.28
Forfeited	(36,800)	$ 23.51
Settled (4)	(113,053)	$ 23.24
Restricted units at December 31, 2007	1,688,540	
Granted (5)	766,200	$ 24.93
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Aggregate grant date fair value of restricted unit awards issued during 2006 was $10.8 million based on grant date market prices of our common units ranging from $24.85 to $27.45 per unit and estimated forfeiture rates ranging from 7.8% to 9.8%.
(3) Aggregate grant date fair value of restricted unit awards issued during 2007 was $18.9 million based on grant date market prices of our common units ranging from $28.00 to $31.83 per unit and estimated forfeiture rates ranging from 4.6% to 17.0%.
(4) Reflects the settlement of restricted units in connection with the resignation of our general partner's former chief executive officer.
(5) Aggregate grant date fair value of restricted unit awards issued during 2008 was $19.1 million based on grant date market prices of our common units ranging from $25.00 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of restricted unit awards that vested during the year ended December 31, 2008 was $6.6 million. At December 31, 2008, there was an estimated $31.5 million of total unrecognized compensation cost related to restricted unit awards granted under the EPCO 1998 Plan, which we expect to recognize over a weighted-average period of 2.3 years. We will recognize our share of such costs in accordance with the ASA.

Phantom unit awards. The EPCO 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is four years from the date the award is granted. No phantom unit awards have been issued to date under the EPCO 1998 Plan.

The EPCO 1998 Plan also provides for the award of distribution equivalent rights ("DERs") in tandem with its phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by us to our unitholders. No DERs have been issued as of December 31, 2008 under the EPCO 1998 Plan.

EPD 2008 LTIP

On January 29, 2008, our unitholders approved the EPD 2008 LTIP, which provides for awards of our 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 EPD 2008 LTIP may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. The EPD 2008 LTIP is administered by EPGP's Audit, Conflicts and Governance ("ACG") Committee. The EPD 2008 LTIP provides for the issuance of up to 10,000,000 of our common units. After giving effect to option awards outstanding at December 31, 2008, a total of 9,205,000 additional common units could be issued under the EPD 2008 LTIP.

The EPD 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The EPD 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Unit option awards. The exercise price of unit options awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of our common units at the date of grant. The following table presents unit option activity under the EPD 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at January 1, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at December 31, 2008 (2)	795,000	$ 30.93	5.00

(1) Aggregate grant date fair value of these unit options issued during 2008 was $1.6 million based on the following assumptions: (i) a grant date market price of our 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 our common units of 7.0%; (v) expected unit price volatility on our common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.
(2) The 795,000 units outstanding at December 31, 2008 will become exercisable in 2013.

At December 31, 2008, there was an estimated $1.3 million of total unrecognized compensation cost related to nonvested unit options granted under the EPD 2008 LTIP. We expect to recognize our share of this cost over a remaining period of 3.4 years in accordance with the ASA.

Phantom unit awards. The EPD 2008 LTIP also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is three years from the date the award is granted. There were a total of 4,400 phantom units granted under the EPD 2008 LTIP during the fourth quarter of 2008 and outstanding at December 31, 2008. These awards cliff vest in 2011. At December 31, 2008, we had an accrued liability of $5 thousand for compensation related to these phantom unit awards.

Employee Partnerships

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 five limited partnerships. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without capital contributions. As discussed and defined above, the Employee Partnerships are: EPE Unit I; EPE Unit II; EPE Unit III; Enterprise Unit; and EPCO Unit. Enterprise Unit and EPCO Unit were formed in 2008.

The Class B limited partner interests entitle each holder to participate in the appreciation in value of the publicly traded limited partner units owned by the underlying Employee Partnership. The Employee Partnerships own either Enterprise GP Holdings units (“EPE units”) or Enterprise Products Partners’ common units (“EPD units”) or both. The Class B limited partner interests are subject to forfeiture if the participating employee’s employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements and upon certain change of control events.

We account for the profits interest awards under SFAS 123(R). As a result, the compensation expense attributable to these awards is based on the estimated grant date fair value of each award. An allocated portion of the fair value of these equity-based awards is charged to us under the ASA (see Note 17). We are not responsible for reimbursing EPCO for any expenses of the Employee Partnerships, including the value of any contributions of cash or limited partner units made by private company affiliates of EPCO at the formation of each Employee Partnership. However, pursuant to the ASA, beginning in February 2009 we will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit.

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 any 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 following table summarizes key elements of each Employee Partnership as of December 31, 2008:

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Award Vesting Date (1)	Grant Date Fair Value of Awards (2)	Unrecognized Compensation Cost (3)
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725% (4)	November 2012	$17.0 million	$9.3 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725% (4)	February 2014	$0.3 million	$0.2 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	May 2014	$32.7 million	$25.1 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2014	$4.2 million	$3.7 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	November 2013	$7.2 million	$7.0 million

(1) The vesting date may be accelerated for change of control and other events as described in the underlying partnership agreements.

(2) Our estimated grant date fair values were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. See following table for information regarding our fair value assumptions.

(3) Unrecognized compensation cost represents the total future expense to be recognized by the EPCO group of companies as of December 31, 2008. We will recognize our allocated share of such costs in the future. The period over which the unrecognized compensation cost will be recognized is as follows for each Employee Partnership: 3.9 years, EPE Unit I; 5.1 years, EPE Unit II; 5.4 years, EPE Unit III; 5.1 years, Enterprise Unit; and 4.9 years, EPCO Unit.

(4) In July 2008, the Class A preferred return was reduced from 6.25% to the floating amounts presented.

The following table summarizes the assumptions we used in deriving the estimated grant date fair value for each of the Employee Partnerships using a Black-Scholes option pricing model:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield of EPE/EPD units	Expected Unit Price Volatility of EPE/EPD units
EPE Unit I	3 to 5 years	2.7% to 5.0%	3.0% to 4.8%	16.6% to 30.0%
EPE Unit II	5 to 6 years	3.3% to 4.4%	3.8% to 4.8%	18.7% to 19.4%
EPE Unit III	4 to 6 years	3.2% to 4.9%	4.0% to 4.8%	16.6% to 19.4%
Enterprise Unit	6 years	2.7% to 3.9%	4.5% to 8.0%	15.3% to 22.1%
EPCO Unit	5 years	2.4%	11.1%	50.0%

DEP GP UARs

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, Enterprise GP Holdings, Duncan Energy Partners or us. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. These UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date fair value. If a director resigns prior to vesting, his UAR awards are forfeited. These UARs are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of December 31, 2008, a total of 90,000 UARs had been 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 an Enterprise GP Holdings' unit price of $36.68.

Note 6. Employee Benefit Plans

Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined Contribution Plan

Dixie contributed $0.3 million to its company-sponsored defined contribution plan for each of the years ended December 31, 2008 and 2007.

Pension and Postretirement Benefit Plans

Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's postretirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table presents Dixie's benefit obligations, fair value of plan assets and funded status at December 31, 2008.

	Pension Plan	Postretirement Plan
Projected benefit obligation	$ 7,733	$ 4,976
Accumulated benefit obligation	5,711	--
Fair value of plan assets	4,035	--
Funded status	(3,698)	(4,976)

Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2008 were as follows: discount rate of 6.4%; rate of compensation increase of 4.0% for both the pension and postretirement plans; and a medical trend rate of 8.5% for 2009 grading to an ultimate trend of 5.0% for 2015 and later years. Dixie's net pension and postretirement benefit costs for 2008 were $0.6 million and $0.4 million, respectively. Dixie's net pension and postretirement benefit costs for 2007 were $1.1 million (including settlement loss of $0.6 million) and $0.4 million, respectively.

Future benefits expected to be paid from Dixie's pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	Postretirement Plan
2009	$ 289	$ 357
2010	334	399
2011	535	427
2012	408	440
2013	775	439
2014 through 2018	4,211	2,067
Total	$ 6,552	$ 4,129

Included in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets at December 31, 2008 and 2007 are the following amounts that have not been recognized in net periodic pension costs (in millions):

	At December 31,	
	2008	2007
Unrecognized transition obligation	$ 0.9	$ 1.0
Net of tax	0.5	0.6
Unrecognized prior service cost credit	(1.0)	(1.2)
Net of tax	(0.6)	(0.8)
Unrecognized net actuarial loss	1.3	2.8
Net of tax	0.8	1.7

Note 7. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates. See Note 14 for information regarding our consolidated debt obligations.

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

The following table presents gains (losses) recorded in net income attributable to our interest rate risk and commodity risk hedging transactions for the periods indicated. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net	$ 4,409	$ 5,429	$ 4,234
Other gains (losses) from derivative transactions	5,340	(8,934)	(5,195)
Duncan Energy Partners:			
Ineffective portion of cash flow hedges	(5)	(155)	--
Reclassification of cash flow hedge amounts from AOCI, net	(2,008)	350	--
Total hedging gains (losses), net, in consolidated interest expense	$ 7,736	$ (3,310)	$ (961)
Commodity Risk Hedging Portfolio:			
EPO:			
Reclassification of cash flow hedge amounts from AOCI, net - natural gas marketing activities	$ (30,175)	$ (3,299)	$ (1,327)
Reclassification of cash flow hedge amounts from AOCI, net - NGL and petrochemical operations	(28,232)	(4,564)	13,891
Other gains (losses) from derivative transactions	29,772	(20,712)	(2,307)
Total hedging gains (losses), net, in consolidated operating costs and expenses	$ (28,635)	$ (28,575)	$ 10,257

The following table provides additional information regarding derivative instruments as presented in our Consolidated Balance Sheets at the dates indicated:

	At December 31,	
	2008	2007
Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$ 7,780	$ --
Commodity risk hedging portfolio	185,762	341
Foreign currency risk hedging portfolio	9,284	1,308
Total derivative assets – current	$ 202,826	$ 1,649
Other assets:		
Interest rate risk hedging portfolio	$ 38,939	$ 14,744
Total derivative assets – long-term	$ 38,939	$ 14,744
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$ 5,910	$ 22,209
Commodity risk hedging portfolio	281,142	19,575
Foreign currency risk hedging portfolio	109	27
Total derivative liabilities – current	$ 287,161	$ 41,811
Other liabilities:		
Interest rate risk hedging portfolio	$ 3,889	$ 3,080
Commodity risk hedging portfolio	233	--
Total derivative liabilities – long-term	$ 4,122	$ 3,080

The following table presents gains (losses) recorded in other comprehensive income (loss) for cash flow hedges associated with our interest rate risk, commodity risk and foreign currency risk hedging portfolios. These amounts do not present the corresponding gains (losses) attributable to the underlying hedged items.

	For the Year Ended December 31,		
	2008	2007	2006
Interest Rate Risk Hedging Portfolio:			
EPO:			
Gains (losses) on cash flow hedges	$ (20,772)	$ 17,996	$ 11,196
Reclassification of cash flow hedge amounts to net income, net	(4,409)	(5,429)	(4,234)
Duncan Energy Partners:			
Losses on cash flow hedges	(7,989)	(3,271)	--
Reclassification of cash flow hedge amounts to net income, net	2,008	(350)	--
Total interest rate risk hedging gains (losses), net	(31,162)	8,946	6,962
Commodity Risk Hedging Portfolio:			
EPO:			
Natural gas marketing activities:			
Losses on cash flow hedges	(30,642)	(3,125)	(1,034)
Reclassification of cash flow hedge amounts to net income, net	30,175	3,299	1,327
NGL and petrochemical operations:			
Gains (losses) on cash flow hedges	(120,223)	(22,735)	9,976
Reclassification of cash flow hedge amounts to net income, net	28,232	4,564	(13,891)
Total commodity risk hedging gains (losses), net	(92,458)	(17,997)	(3,622)
Foreign Currency Risk Hedging Portfolio:			
Gains on cash flow hedges	9,286	1,308	--
Total foreign currency risk hedging gains (losses), net	9,286	1,308	--
Total cash flow hedge amounts in other comprehensive income (loss) (1)	$ (114,334)	$ (7,743)	$ 3,340

(1) Total cash flow hedge amounts in other comprehensive income (loss) include amounts attributable to noncontrolling interest. Such amounts were $1.9 million (loss) and $2.6 million (loss) for the years ended December 31, 2008 and 2007, respectively.

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded in net income and other comprehensive income and on our balance sheet related to our consolidated hedging activities, please refer to the preceding tables.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – EPO interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, we had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $12.9 million (an asset).

The following table summarizes our interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

Cash flow hedges – EPO treasury locks

We may enter into treasury rate lock transactions ("treasury locks") to hedge U.S. treasury rates related to its anticipated issuances of debt. Each of our treasury lock transactions was designated as a cash flow hedge. Gains or losses on the termination of such instruments are reclassified into net income (as a component of interest expense) using the effective interest method over the estimated term of the underlying fixed-rate debt. At December 31, 2008, we had no treasury lock financial instruments outstanding. At December 31, 2007, the aggregate notional value of our treasury lock financial instruments was $600.0 million, which had a total fair value (a liability) of $19.6 million. We terminated a number of treasury lock financial instruments during 2008 and 2007. These terminations resulted in realized losses of $40.4 million in 2008 and gains of $48.8 million in 2007.

We expect to reclassify $1.6 million of cumulative net gains from our interest rate risk cash flow hedges into net income (as a decrease to interest expense) during 2009.

Cash flow hedges – Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 and 2007 was a liability of $9.8 million and $3.8 million, respectively. Duncan Energy Partners expects to reclassify $6.0 million of cumulative net losses from its interest rate risk cash flow hedges into net income (as an increase to interest expense) during 2009.

The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded in other comprehensive income (loss) and amortized into earnings based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas prices during the second half of 2008.   As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity financial instruments we utilize are settled in cash.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with its NGL and petrochemical operations.

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million and a liability of $0.3 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

NGL and petrochemical operations

At December 31, 2008 and 2007, the aggregate fair value of those financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million and $19.0 million, respectively. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting. We expect to reclassify $114.0 million of cumulative net losses from these cash flow hedges into net income (as an increase in operating costs and expenses) during 2009.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity financial instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as financial instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity financial instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the financial instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount it originally hedged under this program.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the year ended December 31, 2008, we recorded minimal gains from these financial instruments.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement ("Yen Term Loan") that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan. Total interest expense under this loan agreement was $4.0 million, of which $1.7 million is the expected foreign currency loss, which will be recorded as interest expense.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at 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.   These assumptions include estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates.   These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

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

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

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

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs. At December 31, 2008 our Level 3 financial assets consisted of ethane based contracts with a range of two to twelve months in term. This classification is primarily due to our reliance on broker quotes for this product due to the forward ethane markets being less than highly active.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity financial instruments	$ 4,030	$ 149,180	$ 32,552	$ 185,762
Foreign currency hedging financial instruments	--	9,284	--	9,284
Interest rate financial instruments	--	46,719	--	46,719
Total	$ 4,030	$ 205,183	$ 32,552	$ 241,765
Financial liabilities:				
Commodity financial instruments	$ 7,137	$ 274,238	$ --	$ 281,375
Foreign currency hedging financial instruments	--	109	--	109
Interest rate financial instruments	--	9,799	--	9,799
Total	$ 7,137	$ 284,146	$ --	$ 291,283

Fair values associated with our interest rate, commodity and foreign currency financial instrument portfolios were developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities during the year ended December 31, 2008:

Balance, January 1, 2008	$ (4,660)
Total gains (losses) included in:	
Net income (1)	(34,807)
Other comprehensive loss	37,212
Purchases, issuances, settlements	34,807
Balance, December 31, 2008	$ 32,552

(1) There were no unrealized gains included in this amounts.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses 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. The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques. The following table presents the estimated fair values of our financial instruments at the dates indicated:

	At December 31, 2008		At December 31, 2007	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents, including restricted cash	$ 239,162	$ 239,162	$ 92,866	$ 92,866
Accounts receivable	1,247,144	1,247,144	2,010,544	2,010,544
Commodity financial instruments (1)	185,762	185,762	341	341
Foreign currency hedging financial instruments (2)	9,284	9,284	1,308	1,308
Interest rate hedging financial instruments (3)	46,719	46,719	14,744	14,744
Financial liabilities:				
Accounts payable and accrued expenses	1,683,105	1,683,105	2,755,647	2,755,647
Fixed-rate debt (principal amount) (4)	7,704,296	6,638,954	5,904,000	5,867,899
Variable-rate debt	1,341,750	1,341,750	992,500	992,500
Commodity financial instruments (1)	281,375	281,375	19,575	19,575
Foreign currency hedging financial instruments (2)	109	109	27	27
Interest rate hedging financial instruments (3)	9,799	9,799	25,289	25,289

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the Canadian dollar and Japanese yen.
(3) Represent interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(4) Due to the distress in the capital markets following the collapse of several major financial entities and uncertainty in the credit markets during 2008, corporate debt securities were trading at significant discounts.

Note 8. Cumulative Effect of Change in Accounting Principle

SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity award is amortized to earnings on a straight-line basis over the requisite service or vesting period for equity awards. Compensation for liability-classified awards is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability awards will be cash settled upon vesting.

Upon adoption of SFAS 123(R), we recognized, as a benefit, the cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of equity awards and the application of an estimated forfeiture rate to unvested awards. See Note 5 for additional information regarding our accounting for equity awards.

The following table shows unaudited pro forma net income for the year ended December 31, 2006, assuming the accounting change noted above was applied retroactively to January 1, 2006.

Pro Forma income statement amounts:		
Historical net income attributable to Enterprise Products Partners L.P.	$	601,155
Adjustments to derive pro forma net income attributable to Enterprise Products Partners L.P.:		
Effect of implementation of SFAS 123(R):		
Remove cumulative effect of change in accounting principle recorded in January 2006		(1,472)
Pro forma net income attributable to Enterprise Products Partners L.P.		599,683
EPGP interest		(96,969)
Pro forma net income allocated to limited partners	$	502,714
Pro forma per unit data (basic):		
Historical units outstanding		414,442
Per unit data:		
As reported	$	1.20
Pro forma	$	1.21
Pro forma per unit data (diluted):		
Historical units outstanding		414,759
Per unit data:		
As reported	$	1.20
Pro forma	$	1.21

Note 9. Inventories

Our inventory amounts were as follows at the dates indicated:

	At December 31,	
	2008	2007
Working inventory (1)	$ 200,439	$ 342,589
Forward sales inventory (2)	162,376	11,693
Total inventory	$ 362,815	$ 354,282

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of identified NGL and natural gas volumes dedicated to the fulfillment of forward sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales were $18.66 billion, $14.51 billion and $11.78 billion for the years ended December 31, 2008, 2007 and 2006, respectively.

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-related prices during the month in which they are acquired. We capitalize as a component of inventory those ancillary costs (e.g. freight-in and other handling and processing charges) incurred in connection with volumes obtained through such contracts.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of 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 a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;
- Write-downs of natural gas inventories are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and
- Write-downs of petrochemical inventories are recorded as a cost of our petrochemical marketing activities or octane additive production business within our Petrochemical Services business segment, as applicable.

For the years ended December 31, 2008, 2007 and 2006, we recognized LCM adjustments of approximately $50.7 million, $13.3 million and $18.6 million, respectively. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 7 for a description of our commodity hedging activities.

Note 10. 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	At December 31, 2008	At December 31, 2007
Plants and pipelines (1)	3-40 (5)	$ 12,296,318	$ 10,884,819
Underground and other storage facilities (2)	5-35 (6)	900,664	720,795
Platforms and facilities (3)	20-31	634,761	637,812
Transportation equipment (4)	3-10	38,771	32,627
Land		54,627	48,172
Construction in progress		1,604,691	1,173,988
Total		15,529,832	13,498,213
Less accumulated depreciation		2,375,058	1,910,949
Property, plant and equipment, net		$ 13,154,774	$ 11,587,264

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; 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, 18-40 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 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, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Depreciation expense (1)	$ 466,054	$ 414,901	$ 350,832
Capitalized interest (2)	$ 71,584	$ 75,476	$ 55,660

(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 proved 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, which increased our basic and diluted earnings per unit by $0.04 from what it would have been absent the change.

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, 2006.

ARO liability balance, December 31, 2006	$ 24,403
Liabilities incurred	1,673
Liabilities settled	(5,069)
Revisions in estimated cash flows	15,645
Accretion expense	3,962
ARO liability balance, December 31, 2007	$ 40,614
Liabilities incurred	1,064
Liabilities settled	(7,229)
Revisions in estimated cash flows	1,163
Accretion expense	2,114
ARO liability balance, December 31, 2008	$ 37,726

Property, plant and equipment at December 31, 2008 and 2007 includes $9.9 million and $10.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. We estimate that accretion expense will approximate $2.1 million for 2009, $2.2 million for 2010, $2.4 million for 2011, $2.6 million for 2012 and $2.9 million for 2013.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2008 and 2007 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

Note 11. Investments in and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 16 for a general discussion of our business segments. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at December 31, 2008	December 31, 2008	December 31, 2007
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$ 37,673	$ 40,129
K/D/S Promix, L.L.C. ("Promix")	50.0%	46,380	51,537
Baton Rouge Fractionators LLC ("BRF")	32.2%	24,160	25,423
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu") (1)	49.0%	35,969	--
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	258,066	235,837
Evangeline (2)	49.5%	4,528	3,490
White River Hub, LLC ("White River Hub") (3)	50.0%	21,387	--
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. ("Poseidon")	36.0%	60,233	58,423
Cameron Highway Oil Pipeline Company ("Cameron Highway") (4)	50.0%	250,833	256,588
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50.0%	104,784	111,221
Neptune	25.7%	52,671	55,468
Nemo (5)	33.9%	432	2,888
Texas Offshore Port System	33.3%	35,890	--
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC ("BRPC")	30.0%	12,633	13,282
La Porte (6)	50.0%	3,887	4,053
Total		$ 949,526	$ 858,339

(1) In December 2008, we acquired a 49.0% ownership interest in Skelly-Belvieu.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) In February 2008, we acquired a 50.0% ownership interest in White River Hub.
(4) During the year ended December 31, 2007, we contributed $216.5 million to Cameron Highway to fund our portion of the repayment of Cameron Highway's debt.
(5) The December 31, 2007 amount includes a $7.0 million non-cash impairment charge attributable to our investment in Nemo.
(6) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

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 and advances to unconsolidated affiliates. At December 31, 2008 and 2007, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Jonah included excess cost amounts totaling $43.7 million and $43.8 million, respectively, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment. Amortization of such excess cost amounts was $2.1 million, $2.6 million and $2.1 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents our equity in earnings of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
VESCO	$ (1,519)	$ 3,507	$ 1,719
Promix	1,977	514	1,353
BRF	1,003	2,010	2,643
Skelly-Belvieu	(31)	--	--
Onshore Natural Gas Pipelines & Services:			
Evangeline	896	183	958
Coyote Gas Treating, LLC (“Coyote”)	--	--	1,676
Jonah	21,408	9,357	238
White River Hub	655	--	--
Offshore Pipelines & Services:			
Poseidon	6,883	10,020	11,310
Cameron Highway	16,358	(11,200)	(11,000)
Deepwater Gateway	17,062	20,606	18,392
Neptune (1)	(5,683)	(821)	(8,294)
Nemo (2)	(973)	(5,977)	1,501
Texas Offshore Port System	(38)	--	--
Petrochemical Services:			
BRPC	1,877	2,266	1,864
La Porte	(771)	(807)	(795)
Total	$ 59,104	$ 29,658	$ 21,565

(1) Equity in earnings from Neptune for 2006 include a $7.4 million non-cash impairment charge.

(2) Equity in earnings from Nemo for 2007 include a $7.0 million non-cash impairment charge.

NGL Pipelines & Services

At December 31, 2008, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

VESCO. We own a 13.1% interest in VESCO, which owns a natural gas processing facility and related assets located in south Louisiana.

Promix. We own a 50.0% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

BRF. We own an approximate 32.2% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

Skelly-Belvieu. In December 2008, we acquired a 49.0% interest in Skelly-Belvieu for $36.0 million. Skelly-Belvieu owns a 570-mile pipeline that transports mixed NGLs to markets in southeast Texas.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2008	2007
BALANCE SHEET DATA:		
Current assets	$ 64,080	$ 112,352
Property, plant and equipment, net	368,059	270,586
Other assets	2,011	11,686
Total assets	$ 434,150	$ 394,624
Current liabilities	$ 50,180	$ 75,314
Other liabilities	24,271	9,095
Combined equity	359,699	310,215
Total liabilities and combined equity	$ 434,150	$ 394,624

	For the Year Ended December 31,		
	2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 271,263	$ 220,381	$ 190,320
Operating income (loss)	20,518	41,147	(26,885)
Net income (loss)	20,872	26,506	(25,543)

Onshore Natural Gas Pipelines & Services

At December 31, 2008, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Evangeline. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline located in south Louisiana. A subsidiary of Acadian Gas, LLC owns the Evangeline interests, which were contributed to Duncan Energy Partners in February 2007 in connection with its initial public offering (see Note 17).

Coyote. We owned a 50.0% interest in Coyote during 2005, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado. During 2006, we sold our interest in Coyote and recorded a gain on the sale of $3.3 million.

Jonah. Our equity interest in Jonah at December 31, 2008 is based on capital contributions we made to Jonah in connection with its Phase V expansion project. We completed Phase I of this expansion in July 2007 entitling us to approximately 19.4% in earnings and ownership with the remaining 80.6% entitlement to TEPPCO. See Note 17 for additional information regarding our Jonah affiliate. Jonah owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming.

White River Hub. We own a 50.0% interest in White River Hub, which owns a natural gas hub located in northwest Colorado. The hub was completed in December 2008.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2008	2007
BALANCE SHEET DATA:		
Current assets	$ 97,470	$ 83,962
Property, plant and equipment, net	1,082,251	915,572
Other assets	158,682	176,091
Total assets	$ 1,338,403	$ 1,175,625
Current liabilities	$ 62,147	$ 43,951
Other liabilities	21,890	25,002
Combined equity	1,254,366	1,106,672
Total liabilities and combined equity	$ 1,338,403	$ 1,175,625

	For the Year Ended December 31,		
	2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 605,353	$ 477,077	$ 372,240
Operating income	118,907	98,549	48,387
Net income	114,911	93,491	40,608

Offshore Pipelines & Services

At December 31, 2008, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36.0% interest in Poseidon, which owns 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.

Cameron Highway. We own a 50.0% interest in Cameron Highway, which owns 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.

Cameron Highway repaid its $365.0 million Series A notes and $50.0 million Series B notes in 2007 using cash contributions from its partners. We funded our 50.0% 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.

Deepwater Gateway. We own a 50.0% interest in Deepwater Gateway, which owns the Marco Polo platform located in the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

Neptune. We own a 25.7% interest in Neptune, which owns Manta Ray Offshore Gathering System ("Manta Ray") and Nautilus Pipeline System ("Nautilus"), which are natural gas pipelines located in the Gulf of Mexico.

Nemo. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

Texas Offshore Port System. In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels. We own a one-third interest in the Texas Offshore Port System. See Note 17 for additional information regarding this joint venture.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2008	2007
BALANCE SHEET DATA:		
Current assets	$ 106,392	$ 46,795
Property, plant and equipment, net	1,184,549	1,122,108
Other assets	3,608	4,338
Total assets	$ 1,294,549	$ 1,173,241
Current liabilities	$ 58,379	$ 19,720
Other liabilities	116,654	96,791
Combined equity	1,119,516	1,056,730
Total liabilities and combined equity	$ 1,294,549	$ 1,173,241

	For the Year Ended December 31,		
	2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 163,916	$ 156,780	$ 153,996
Operating income	68,969	85,550	71,977
Net income	65,554	53,590	42,732

Neptune owns Manta Ray and Nautilus. Manta Ray gathers natural gas originating 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 the Nautilus pipeline. Nautilus connects our Manta Ray pipeline to our Neptune natural gas processing plant located in south Louisiana. Due to a recent decrease in throughput volumes on the Manta Ray and Nautilus pipelines, we evaluated our 25.7% investment in Neptune for impairment during the third quarter of 2006. The decrease in throughput volumes is primarily due to underperformance of certain fields, natural depletion and hurricane-related delays in starting new production. These factors contributed to significant delays in throughput volumes Neptune expects to receive. As a result, Neptune has experienced operating losses in recent periods.

Our review of Neptune's estimated cash flows during the third quarter of 2006 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.4 million. This loss is recorded as a component of "Equity in earnings of unconsolidated affiliates" in our Statement of Consolidated Operations for the year ended December 31, 2006.

Nemo was formed in 1999 to construct, own and operate the Nemo Gathering System, a 24-mile natural gas gathering system in the Gulf of Mexico offshore Louisiana. The Nemo Gathering System, which began operations in 2001, gathers natural gas from certain developments in the Green Canyon area of the Gulf of Mexico to a pipeline interconnect with the Manta Ray Gathering System. Due to a recent decrease in throughput volumes on the Nemo Gathering System, we evaluated our 33.9% investment in Nemo for impairment during the second quarter of 2007. The decrease in throughput volumes is primarily due to underperformance of certain fields and natural depletion.

Our review of Nemo's estimated future cash flows during the second quarter of 2007 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.0 million. This loss is recorded as a component of "Equity in earnings of unconsolidated affiliates" in our Statement of Consolidated Operations for the year ended December 31, 2007. After recording this impairment charge, the carrying value of our investment in Nemo at December 31, 2007 was $2.9 million.

Our investments in Neptune and Nemo were written down to fair value, which management estimated using recognized business valuation techniques. The fair value analysis is based upon management's expectation of future cash flows, which incorporates certain industry information and assumptions made by management. For example, the individual reviews of Neptune and Nemo included management estimates regarding natural gas reserves of producers served by both Neptune and Nemo, respectively. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

Petrochemical Services

At December 31, 2008, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30.0% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50.0% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2008	2007
BALANCE SHEET DATA:		
Current assets	$ 3,634	$ 3,187
Property, plant and equipment, net	43,720	47,322
Total assets	$ 47,354	$ 50,509
Current liabilities	$ 1,737	$ 970
Other liabilities	2	2
Combined equity	45,615	49,537
Total liabilities and combined equity	$ 47,354	$ 50,509

	For the Year Ended December 31,		
	2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 20,990	$ 19,844	$ 19,014
Operating income	4,666	5,961	4,626
Net income	4,693	6,029	4,729

Note 12. Business Combinations

2008 Transactions

Our expenditures for business combinations during the year ended December 31, 2008 were $202.2 million and primarily reflect the acquisitions described below.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts would not have differed materially from those we actually reported for 2008, 2007 and 2006 due to the immaterial nature of our 2008 business combination transactions.

Great Divide Gathering System Acquisition. In December 2008, one of our affiliates, Enterprise Gas Processing, LLC, purchased a 100.0% 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 31-mile natural gas gathering system, the Great Divide Gathering System, located in the Piceance Basin of northwestern 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 1.4 Bcf/d Meeker natural gas treating and processing complex. A significant portion of these volumes are produced by EnCana, one of the largest natural gas producers in the region, and are dedicated the Great Divide and Piceance Creek Gathering Systems for the life of the associated lease holdings.

Tri-States and Belle Rose Acquisitions. In October 2008, we acquired additional 16.7% membership interests in both Tri-States NGL Pipeline, L.L.C. ("Tri-States") and Belle Rose NGL Pipeline, L.L.C. ("Belle Rose") for total cash consideration of $19.9 million. As a result of this transaction, our ownership interest in Tri-States increased to 83.3%. We now own 100.0% of the membership interests in Belle Rose.

Tri-States owns a 194-mile NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. Belle Rose owns a 48-mile NGL pipeline located in Louisiana. These systems, in conjunction with the Wilprise pipeline, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana.

Acquisition of Remaining Interest in Dixie. In August 2008, we acquired the remaining 25.8% ownership interests in Dixie for cash consideration of $57.1 million. As a result of this transaction, we own 100.0% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstock) to customers along the U.S. Gulf Coast and southeastern United States.

Purchase Price Allocations. We accounted for business combinations completed during the year ended December 31, 2008 using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

	Great Divide	Tri-States	Belle Rose	Dixie	Other (1)	Total
Assets acquired in business combination:						
Current assets	$ --	$ 813	$ 143	$ 4,021	$ 35	$ 5,012
Property, plant and equipment, net	70,643	18,417	1,129	33,727	(12,773)	111,143
Intangible assets	9,760	--	--	--	12,747	22,507
Other assets	--	46	--	382	--	428
Total assets acquired	80,403	19,276	1,272	38,130	9	139,090
Liabilities assumed in business combination:						
Current liabilities	--	(581)	(68)	(2,581)	--	(3,230)
Long-term debt	--	--	--	(2,582)	--	(2,582)
Other long-term liabilities	(81)	--	(4)	(46,265)	--	(46,350)
Total liabilities assumed	(81)	(581)	(72)	(51,428)	--	(52,162)
Total assets acquired plus liabilities assumed	80,322	18,695	1,200	(13,298)	9	86,928
Total cash used for business combinations	125,175	18,695	1,200	57,089	1	202,160
Goodwill	$ 44,853	$ --	$ --	$ 70,387	$ (8)	$ 115,232

(1) Primarily represents non-cash reclassification adjustments to December 2007 preliminary fair value estimates for assets acquired in the South Monco natural gas pipeline business ("South Monco") acquisition.

As a result of our 100% ownership interest in Dixie, we used push-down accounting to record this business combination. In doing so, a temporary tax difference was created between the assets and liabilities of Dixie for financial reporting and tax purposes. Dixie recorded a deferred income tax liability of $45.1 million attributable to the temporary tax difference.

2007 Transactions

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts would not have differed materially from those we actually reported for 2007 and 2006 due to immaterial nature of our 2007 business combination transactions.

Our expenditures for business combinations during the year ended December 31, 2007 were $35.8 million, which primarily reflect the $35.0 million we spent to acquire South Monco in December 2007. This business includes approximately 128 miles of natural gas pipelines located in southeast Texas. The remaining business combination related amounts for 2007 consist of purchase price adjustments to prior period transactions.

We accounted for our 2007 business combinations using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

2006 Transactions

Our expenditures for business combinations during the year ended December 31, 2006 were $276.5 million and primarily reflect the Encinal and Piceance Creek acquisitions described below.

Encinal Acquisition. In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts that comprised the South Texas natural gas transportation and processing business of an affiliate of Lewis Energy Group, L.P. (“Lewis”). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the “Encinal acquisition”) was $326.3 million, which consisted of $145.2 million in cash and 7,115,844 of our common units.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas wells producing from the Olmos and Wilcox formations. The Encinal system consists of 449 miles of pipeline, which is comprised of 277 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing Texas Intrastate System and are processed by our South Texas natural gas processing plants.

The Encinal and Canales gathering systems will be supported by a life of reserves gathering and processing dedication by Lewis related to its natural gas production from the Olmos formation. In addition, we entered into a 10-year agreement with Lewis for the transportation of natural gas treated at its proposed Big Reef facility. This facility will treat natural gas from the southern portion of the Edwards Trend in South Texas. We also entered into a 10-year agreement with Lewis for the gathering and processing of rich gas it produces from below the Olmos formation.

The total consideration we paid or granted to Lewis in connection with the Encinal acquisition is as follows:

Cash payment to Lewis	$	145,197
Fair value of our 7,115,844 common units issued to Lewis		181,112
Total consideration	$	326,309

In accordance with purchase accounting, the value of our common units issued to Lewis was based on the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. For purposes of this calculation, the average closing price was $25.45 per unit.

Since the closing date of the Encinal acquisition was July 1, 2006, our Statements of Consolidated Operations do not include any earnings from these assets prior to this date. Given the relative size of the Encinal acquisition to our other business combination transactions during 2006, the following table presents selected pro forma earnings information for the year ended December 31, 2006 as if the Encinal acquisition had been completed on January 1, 2006, instead of July 1, 2006. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Encinal acquisition actually occurred on January 1, 2006. The amounts shown in the following table are in millions, except per unit amounts.

		For the Year Ended December 31, 2006
Pro forma earnings data:		
Revenues	$	14,066
Costs and expenses		13,228
Operating income		859
Net income attributable to Enterprise Products Partners L.P.		598
Basic earnings per unit ("EPU"):		
Units outstanding, as reported		414
Units outstanding, pro forma		422
Basic EPU, as reported	$	1.20
Basic EPU, pro forma	$	1.19
Diluted EPU:		
Units outstanding, as reported		415
Units outstanding, pro forma		422
Diluted EPU, as reported	$	1.20
Diluted EPU, pro forma	$	1.19

Piceance Creek Acquisition. In December 2006, we purchased a 100.0% interest in Piceance Creek Pipeline, LLC ("Piceance Creek"), for $100.0 million. Piceance Creek was wholly owned by EnCana.

The assets of Piceance Creek consist of a recently constructed 48-mile natural gas gathering pipeline, the Piceance Creek Gathering System, located in the Piceance Basin of northwestern Colorado. The Piceance Creek Gathering System has a transportation capacity of 1.6 Bcf/d of natural gas and extends from a connection with EnCana's Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.4 Bcf/d Meeker natural gas treating and processing complex. Connectivity to EnCana's Great Divide Gathering System (see above for our purchase of this system in 2008) will provide the Piceance Creek Gathering System with access to production from the southern portion of the Piceance basin, including production from EnCana's Mamm Creek field. The Piceance Creek Gathering System was placed in service in January 2007 and began transporting initial volumes of approximately 300 million cubic feet per day ("MMcf/d") of natural gas. In conjunction with our acquisition of Piceance Creek, EnCana signed a long-term, fixed fee gathering agreement with us and dedicated significant production to the Piceance Creek Gathering System for the life of the associated lease holdings.

Other Transactions. In addition to the Encinal and Piceance Creek acquisitions, our business combinations during 2006 included the purchase of (i) an additional 8.2% ownership interest in Dixie for $12.9 million, (ii) all of the capital stock of an affiliated NGL marketing company located in Canada from related parties for $17.7 million (see Note 17) and (iii) a storage business in Flagstaff, Arizona for $0.7 million.

Note 13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	At December 31, 2008			At December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Shell Processing Agreement	$ 206,216	$ (89,299)	$ 116,917	$ 206,216	$ (78,252)	$ 127,964
Encinal gas processing customer relationship	127,119	(28,045)	99,074	127,119	(17,470)	109,649
STMA and GulfTerra NGL Business customer relationships	49,784	(21,570)	28,214	49,784	(17,537)	32,247
Pioneer gas processing contracts	37,752	(3,601)	34,151	37,752	(736)	37,016
Markham NGL storage contracts	32,664	(18,509)	14,155	32,664	(14,154)	18,510
Toca-Western contracts	31,229	(10,280)	20,949	31,229	(8,718)	22,511
Other (1)	52,295	(14,745)	37,550	35,261	(10,087)	25,174
Segment total	537,059	(186,049)	351,010	520,025	(146,954)	373,071
Onshore Natural Gas Pipelines & Services:						
San Juan Gathering System customer relationships	331,311	(92,471)	238,840	331,311	(73,087)	258,224
Petal & Hattiesburg natural gas storage contracts	100,499	(36,524)	63,975	100,499	(27,931)	72,568
Other (2)	41,501	(10,854)	30,647	31,741	(8,381)	23,360
Segment total	473,311	(139,849)	333,462	463,551	(109,399)	354,152
Offshore Pipelines & Services:						
Offshore pipeline & platform customer relationships	205,845	(90,686)	115,159	205,845	(73,905)	131,940
Other	1,167	(107)	1,060	1,167	(49)	1,118
Segment total	207,012	(90,793)	116,219	207,012	(73,954)	133,058
Petrochemical Services:						
Mont Belvieu propylene fractionation contracts	53,000	(10,474)	42,526	53,000	(8,960)	44,040
Other (3)	14,906	(2,707)	12,199	14,906	(2,227)	12,679
Segment total	67,906	(13,181)	54,725	67,906	(11,187)	56,719
Total all segments	$ 1,285,288	$ (429,872)	$ 855,416	$ 1,258,494	$ (341,494)	$ 917,000

(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 the December 2007 South Monco acquisition.
(2) In 2008, we acquired $9.8 million of customer relationships due to the Great Divide business combination.
(3) In 2007, we paid $11.2 million for certain air emission credits related to our Morgan's Point facility.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services	$ 39,095	$ 36,419	$ 31,159
Onshore Natural Gas Pipelines & Services	30,450	31,997	33,447
Offshore Pipelines & Services	16,839	19,318	22,156
Petrochemical Services	1,994	1,993	1,993
Total all segments	$ 88,378	$ 89,727	$ 88,755

We estimate that amortization expense associated with existing intangible assets will approximate $82.7 million in 2009, $77.8 million in 2010, $71.9 million in 2011, $62.3 million in 2012 and $56.4 million in 2013.

In general, our intangible assets fall within two categories – contract-based intangible assets and customer relationships. Contract-based intangible assets represent commercial rights we acquired in connection with business combinations or asset purchases. Customer relationship intangible assets represent customer bases that we acquired in connection with business combinations and asset purchases. The values assigned to 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.

We acquired $141.3 million of intangible assets primarily attributable to customer relationships we acquired in connection with the Encinal acquisition. The $132.9 million of intangible assets we acquired in connection with the Encinal acquisition (see Note 12) represents the value we assigned to customer relationships, particularly the long-term relationship we now have with Lewis through natural gas processing and gathering arrangements. We recorded $127.1 million in our NGL Pipelines & Services segment associated with processing arrangements and $5.8 million in our Onshore Natural Gas Pipelines & Services segment associated with gathering arrangements. These intangible assets will be amortized to earnings over a 20-year life using methods that closely resemble the pattern in which we estimate the depletion of the underlying natural gas resources to occur.

We acquired numerous customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by GulfTerra and the South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts to provide storage services for natural gas and NGLs that GulfTerra had entered into prior to the merger.

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 based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (iv) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets we acquired in connection with the GulfTerra Merger are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

The Shell Processing Agreement grants us the right to process Shell's (or its assignee's) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this intangible asset in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

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. The following table summarizes our goodwill amounts by segment at the dates indicated:

	At December 31, 2008	At December 31, 2007
NGL Pipelines & Services		
GulfTerra Merger	$ 23,854	$ 23,854
Acquisition of Indian Springs natural gas processing business	13,162	13,162
Acquisition of Encinal	95,272	95,280
Acquisition of interest in Dixie	80,279	9,892
Acquisition of Great Divide	44,853	--
Other	11,518	11,518
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	279,956	279,956
Acquisition of Indian Springs natural gas gathering business	2,165	2,165
Offshore Pipelines & Services		
GulfTerra Merger	82,135	82,135
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation business	73,690	73,690
Total	$ 706,884	$ 591,652

In 2008, our only significant changes to goodwill were the recording of $70.4 million in connection with our acquisition of the remaining third party interest in Dixie and $44.9 million in connection 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 100.0% 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 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. For additional information see Note 12.

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.

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.

The remainder of our goodwill amounts is associated with prior acquisitions, principally that of 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 14. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	At December 31,	
	2008	**2007**
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 800,000	$ 725,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Petal GO Zone Bonds, variable rate, due August 2037	57,500	57,500
Yen Term Loan, 4.93% fixed-rate, due March 2009 (1)	217,596	--
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009 (1)	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Senior Notes L, 6.30% fixed-rate, due September 2017	800,000	800,000
Senior Notes M, 5.65% fixed-rate, due April 2013	400,000	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700,000	--
Senior Notes O, 9.75% fixed-rate, due January 2014	500,000	--
Duncan Energy Partners' debt obligations:		
DEP I Revolving Credit Facility, variable rate, due February 2011	202,000	200,000
DEP II Term Loan Agreement, variable rate, due December 2011	282,250	--
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	--	10,000
Total principal amount of senior debt obligations	7,813,346	5,646,500
EPO Junior Subordinated Notes A, fixed/variable rate, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, fixed/variable rate, due January 2068	682,700	700,000
Total principal amount of senior and junior debt obligations	9,046,046	6,896,500
Other, non-principal amounts:		
Change in fair value of debt-related financial instruments (see Note 7)	51,935	14,839
Unamortized discounts, net of premiums	(7,306)	(5,194)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 7)	17,735	--
Total other, non-principal amounts	62,364	9,645
Total long-term debt	$ 9,108,410	$ 6,906,145
Standby letters of credit outstanding	$ 1,000	$ 1,100

(1) In accordance with SFAS 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at December 31, 2008. With respect to the Yen Term Loan and Senior Notes F due in October 2009, we have the ability to use available credit capacity under EPO's Multi-Year Revolving Credit Facility to fund the repayment of this debt.
(2) The Dixie Revolving Credit Facility was terminated in January 2009.

Letters of credit

At December 31, 2008, we had $1.0 million in standby letters outstanding under Duncan Energy Partners' DEP I Revolving Credit Facility. At December 31, 2007, we had $1.1 million of standby letters of credit outstanding under Duncan Energy Partners' DEP I Revolving Credit Facility.

Parent-Subsidiary guarantor relationships

Enterprise Partners Products L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP I Revolving Credit Facility and the DEP II 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.

EPO's debt obligations

Multi-Year Revolving Credit Facility. In November 2007, EPO executed an amended and restated Multi-Year Revolving Credit Facility totaling $1.75 billion, which replaced an existing $1.25 billion multi-year revolving credit agreement. Amounts borrowed under the amended and restated credit agreement mature in November 2012, although EPO is permitted, 30 to 60 days before the maturity date in effect, to convert the principal balance of the revolving loans then outstanding into a non-revolving, one-year term loan (the "term-out option"). There is no sublimit on the amount of standby letters of credit that can be outstanding under the amended facility. EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

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 0.10% per annum for each day that the total outstanding loans and letter of credit obligations under the facility exceeds 50.0% of the total lender commitments. Also, upon the conversion of the revolving loans to term loans pursuant to the term-out option described above, the applicable margin will increase by 0.125% per annum and, if immediately prior to such conversion, the total amount of outstanding loans and letter of credit obligations under the facility exceeds 50.0% of the total lender commitments, the applicable margin with respect to the term loans will increase by an additional 0.10% per annum.

EPO may increase the amount that may be borrowed under the facility, without the consent of the lenders, by an amount not exceeding $500.0 million by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. EPO may request unlimited one-year extensions of the maturity date by delivering a written request to the administrative agent, but any such extension shall be effective only if consented to by the required lenders in their sole discretion.

The Multi-Year Revolving Credit Facility contains various covenants related to EPO's ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires EPO to satisfy certain financial covenants at the end of each fiscal quarter. The credit agreement also restricts EPO's ability to pay cash distributions to us 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.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant in 2000, EPO entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility.

The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest, would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Petal GO Zone Bonds. In August 2007, Petal borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal Gas Storage, L.L.C. ("Petal") and the MBFC to pay a portion of the costs of certain natural gas storage facilities located in Petal, Mississippi. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by Petal. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt ("GO Zone") bonds to various third parties. A portion of the GO Zone bond proceeds were being held by a third party trustee and reflected as a component of other assets on our balance sheet. During 2008, virtually all proceeds from the GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. At December 31, 2007, $17.9 million of the GO Zone bond proceeds remained held by the third party trustee. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of 30 years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act and the Gulf Opportunity Zone Act of 2005.

Petal MBFC Loan. In August 2007, Petal, a wholly owned subsidiary of EPO, 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. As of December 31, 2008, there was $8.9 million outstanding under the loan and the bonds. EPO will make advances on the bonds to the MBFC and the MBFC will in turn make identical advances to Petal under the promissory note. The promissory note and the taxable bonds have identical terms including fixed interest rates of 5.90% and maturities of fifteen years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act. Petal may prepay on the promissory note without penalty, and thus cause the bonds to be redeemed, any time after one year from their date of issue. The loan and bonds are netted in preparing our Consolidated Balance Sheets, as well the related interest expense and income amounts are netted in preparing our Statements of Consolidated Operations.

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's obligations under the Yen Term Loan are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The Yen Term Loan will mature on March 30, 2009.

Under the Yen Term Loan, interest accrues on the loan at the Tokyo Interbank Offered Rate ("TIBOR") plus 2.0%. EPO entered into foreign exchange currency swaps that effectively convert the TIBOR loan into a U.S. Dollar loan with a fixed interest rate (including the cost of the swaps) through maturity of approximately 4.93%. As a result, EPO received US$217.6 million net from this transaction. In addition, EPO executed a forward purchase exchange (yen principal and interest due) for March 30, 2009 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. For additional information see Note 7.

364-Day Revolving Credit Facility. In November 2008, EPO executed a 364-Day Revolving Credit Agreement ("364-Day Revolving Credit Facility") in the amount of $375.0 million. EPO's obligations under the 364-Day Revolving Credit Facility are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The 364-Day Revolving Credit Facility will mature on November 16, 2009. As of December 31, 2008, there were no borrowings outstanding under this credit facility.

The 364-Day Revolving Credit Facility offers the following loans, each having different interest requirements: (i) LIBOR loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin and (ii) Base Rate loans bear interest each day at a rate per annum equal to the higher of (a) the rate of interest announced by the administrative agent as its prime rate, (b) 0.5% per annum above the Federal Funds Rate in effect on such date , and (c) 1.0% per annum above LIBOR in effect on such date plus, in each case, the applicable Base Rate margin.

The commitments may be increased by an amount not to exceed $1.0 billion by adding one or more new lenders to the facility or increasing the commitments of existing lenders, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. With certain exceptions and after certain time periods, if EPO issues debt with a maturity of more than three years, the lenders' commitments under the 364-Day Revolving Credit Facility will be reduced to the extent of any debt proceeds, and any outstanding loans in excess of such reduced commitments must be repaid.

Senior Notes B through L. These 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. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to EPGP. The 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.

EPO used net proceeds from its issuance of Senior Notes L in 2007 to temporarily reduce indebtedness outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2007, EPO used borrowing capacity under its Multi-Year Revolving Credit Facility to repay its $500.0 million Senior Notes E.

Senior Notes M and N. In April 2008, EPO sold $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes M") and $700.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes N") under its universal registration statement. Senior Notes M were issued at 99.906% of their principal amount, have a fixed interest rate of 5.65% and mature in April 2013. Senior Notes N were issued at 99.866% of their principal amount, have a fixed interest rate of 6.50% and mature in January 2019.

Senior Notes M pay interest semi-annually in arrears on April 1 and October 1 of each year. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes M and N rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes M and N 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.

Senior Notes O. In December 2008, EPO sold $500.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes O") under its universal registration statement. Senior Notes O were issued at 100.0% of their principal amount, have a fixed interest rate of 9.75% and mature in January 2014.

Senior Notes O pay interest semi-annually in arrears on January 31 and July 31 of each year, commencing January 31, 2009. Net proceeds from the issuance of Senior Notes O were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes O rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes O 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.

Junior Notes A. In the third quarter of 2006, EPO sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 ("Junior Notes A"). EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year

Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). We guaranteed EPO's repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows EPO to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the indenture agreement has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, neither we nor EPO cannot declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinated to the Junior Notes A.

The Junior Notes A bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, which commenced in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by EPO prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, EPO entered into a Replacement Capital Covenant in favor of the 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.

Junior Notes B. EPO sold $700.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 ("Junior Notes B") during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B 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 we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with Junior Notes A.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, which commenced in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month LIBOR for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that neither we nor EPO would redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

During the fourth quarter of 2008, we retired $17.3 million of our Junior Notes B for $10.2 million. The $7.1 million gain on extinguishment of debt is included in “Other, net” on our Statement of Consolidated Operations.

Duncan Energy Partners’ debt obligations

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

DEP I Revolving Credit Facility. In February 2007, Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund a $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At December 31, 2008, the principal balance outstanding under this facility was $202.0 million.

This credit facility matures in February 2011 and 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 (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy 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 increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

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 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 II Term Loan Agreement. 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 the DEP II Midstream Businesses. See “Relationship with Duncan Energy Partners” in Note 17 for additional information regarding the DEP II Midstream Businesses.

Loans under the term loan agreement are due and payable on December 8, 2011. Duncan Energy Partners may also 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 ("ABR") loans or Eurodollar loans. The term loan agreement contains 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. As of December 31, 2008, there were no debt obligations outstanding under the Dixie Revolver. This credit facility was terminated in January 2009. EPO consolidated the debt of Dixie; however, EPO did not have the obligation to make interest or debt payments with respect to Dixie's debt.

Variable interest rates charged under this facility generally bore interest, at Dixie's election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the prime rate or (b) the Federal Funds Effective Rate plus 0.5%.

Canadian Debt Obligation

In May 2007, Canadian Enterprise Gas Products, Ltd. ("Canadian Enterprise"), 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.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate ("CPR") loans or Bankers' Acceptances and U.S. denominated borrowings may be comprised of ABR or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers' Acceptances carry interest at the rate for Canadian bankers' acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2008, there were no debt obligations outstanding under this credit facility.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2008 and 2007.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2008.

	Range of Interest Rates Paid	**Weighted-Average Interest Rate Paid**
EPO's Multi-Year Revolving Credit Facility	0.97% to 6.00%	3.54%
DEP I Revolving Credit Facility	1.30% to 6.20%	4.25%
DEP II Term Loan Agreement	2.93% to 2.93%	2.93%
Dixie Revolving Credit Facility	0.81% to 5.50%	3.20%
Petal GO Zone Bonds	0.78% to 7.90%	2.24%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2009	$ --
2010	554,000
2011	934,250
2012	1,517,596
2013	750,000
Thereafter	5,290,200
Total scheduled principal payments	$ 9,046,046

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2008, (ii) total debt of each unconsolidated affiliate at December 31, 2008 (on a 100.0% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2009	2010	2011	2012	2013	After 2013
Poseidon	36.0%	$ 109,000	$ --	$ --	$ 109,000	$ --	$ --	$ --
Evangeline	49.5%	15,650	5,000	3,150	7,500	--	--	--
Total		$ 124,650	$ 5,000	$ 3,150	$ 116,500	$ --	$ --	$ --

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at December 31, 2008 and 2007. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid. Cameron Highway repaid its debt obligations during the second quarter of 2007 using pro rata capital contributions from EPO and its joint venture partner in Cameron Highway.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2008:

Poseidon. Poseidon has $109.0 million outstanding under its $150.0 million revolving credit facility that matures in May 2011. Interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon’s total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon’s assets. The variable interest rates charged on this debt at December 31, 2008 and 2007 were 4.31% and 6.62%, respectively.

Evangeline. At December 31, 2008, short and long-term debt for Evangeline consisted of (i) $8.2 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. 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. Scheduled principal repayments on the Series B notes are $5.0 million in 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the 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 a Eurodollar rate plus 0.5%. The variable interest rates charged on this note at December 31, 2008 and 2007 were 3.20% and 5.88%, respectively. Accrued interest payable related to the subordinated note was $9.8 million and $9.1 million at December 31, 2008 and 2007, respectively.

Note 15. Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the “Partnership Agreement”). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

In August 2005, we revised our Partnership Agreement to allow EPGP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2.0% general partner interest would be proportionately reduced. At the time of such offerings, EPGP has historically contributed cash to us to maintain its 2.0% general partner interest. EPGP made such cash contributions to us during the years ended December 31, 2008 and 2007. If EPGP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, EPGP can, under certain conditions, restore its full 2.0% general partner interest by making additional cash contributions to us.

Equity offerings and registration statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by EPGP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

In August 2007, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities. In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this universal shelf registration. See Note 25 for additional information.

During 2003, we instituted a distribution reinvestment plan (“DRIP”). In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our 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. A total of 21,471,047 common units have been issued under this registration statement through December 31, 2008.

We also have a registration statement on file related to our employee unit purchase plan ("EUPP"), under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10.0% discount through payroll deductions. A total of 651,297 common units have been issued to employees under this plan through December 31, 2008.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the years ended December 31, 2008, 2007 and 2006:

	Net Proceeds from Sale of Common Units			
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
Fiscal 2006:				
Underwritten offerings	31,050,000	$ 735,819	$ 15,003	$ 750,822
DRIP and EUPP	3,774,649	95,006	1,940	96,946
Total 2006	34,824,649	$ 830,825	$ 16,943	$ 847,768
Fiscal 2007:				
DRIP and EUPP	2,056,615	$ 60,445	$ 1,232	$ 61,677
Total 2007	2,056,615	$ 60,445	$ 1,232	$ 61,677
Fiscal 2008:				
DRIP and EUPP	5,523,946	$ 139,248	$ 2,842	$ 142,090
Total 2008	5,523,946	$ 139,248	$ 2,842	$ 142,090

Net proceeds received from our underwritten and other offerings completed during 2006 were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Net proceeds received from our DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

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

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2005	389,109,564	751,604	--
Common units issued in connection with underwritten offerings	31,050,000	--	--
Common units issued in connection with DRIP and EUPP	3,774,649	--	--
Common units issued in connection with equity awards	211,000	466,400	--
Forfeiture of restricted units	--	(70,631)	--
Conversion of restricted units to common units	42,136	(42,136)	--
Common units issued in connection with Encinal acquisition	7,115,844	--	--
Balance, December 31, 2006	431,303,193	1,105,237	--
Common units issued in connection with DRIP and EUPP	2,056,615	--	--
Common units issued in connection with equity awards	244,071	738,040	--
Forfeiture or settlement of restricted units	--	(149,853)	--
Conversion of restricted units to common units	4,884	(4,884)	--
Balance, December 31, 2007	433,608,763	1,688,540	--
Common units issued in connection with DRIP and EUPP	5,523,946	--	--
Common units issued in connection with equity awards	21,905	--	--
Restricted units issued	--	766,200	--
Forfeiture or settlement of restricted units	--	(88,777)	--
Conversion of restricted units to common units	285,363	(285,363)	--
Acquisition of treasury units	(85,246)	--	85,246
Cancellation of treasury units	--	--	(85,246)
Balance, December 31, 2008	439,354,731	2,080,600	--

Treasury Units. In 2000, we and a consolidated trust (the "1999 Trust") were authorized by EPGP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2008.

During the year ended December 31, 2008, 285,363 restricted unit awards vested and were converted to common units. Of this amount, 85,246 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately $1.9 million, of which a minimal amount was allocated to our general partner. Immediately upon acquisition, we cancelled such treasury units.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2005:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2005	$ 5,542,700	$ 18,638	$ 5,561,338
Net income allocated to limited partners	502,969	1,187	504,156
Operating leases paid by EPCO	2,062	5	2,067
Cash distributions to partners	(738,004)	(1,628)	(739,632)
Unit option reimbursements to EPCO	(1,818)	--	(1,818)
Net proceeds from issuance of common units	830,825	--	830,825
Common units issued in connection with Encinal acquisition	181,112	--	181,112
Proceeds from exercise of unit options	5,601		5,601
Amortization of equity awards	2,209	6,073	8,282
Change in accounting method for equity awards (see Note 5)	(896)	(14,919)	(15,815)
Acquisition-related disbursement of cash	(6,183)	(16)	(6,199)
Balance, December 31, 2006	6,320,577	9,340	6,329,917
Net income allocated to limited partners	416,323	1,405	417,728
Operating leases paid by EPCO	2,056	7	2,063
Cash distributions to partners	(831,155)	(2,638)	(833,793)
Unit option reimbursements to EPCO	(2,999)	--	(2,999)
Net proceeds from issuance of common units	60,445	--	60,445
Proceeds from exercise of unit options	7,549	--	7,549
Repurchase of restricted units and options	(512)	(1,056)	(1,568)
Amortization of equity awards	4,663	8,890	13,553
Balance, December 31, 2007	5,976,947	15,948	5,992,895
Net income allocated to limited partners	807,894	3,653	811,547
Operating leases paid by EPCO	1,988	9	1,997
Cash distributions to partners	(888,802)	(3,891)	(892,693)
Unit option reimbursements to EPCO	(550)	--	(550)
Non-cash distributions	(7,140)	--	(7,140)
Acquisition of treasury units, limited partner share	--	(1,873)	(1,873)
Net proceeds from issuance of common units	139,248	--	139,248
Proceeds from exercise of unit options	679	--	679
Amortization of equity awards	6,623	12,373	18,996
Balance, December 31, 2008	$ 6,036,887	$ 26,219	$ 6,063,106

In October 2006, we acquired all of the capital stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan for $17.7 million in cash. The amount we paid for this business exceeded the carrying values of the assets acquired and liabilities assumed from this related party (which is under common control with us) by $6.3 million, of which $6.2 million was allocated to limited partners and $0.1 million to our general partner. The excess of the acquisition price over the net book value of this business at the time of acquisition is treated as a deemed distribution to our owners and presented as an "Acquisition-related disbursement of cash" in our Statement of Equity for the year ended December 31,

2006. The total purchase price is a component of "Cash used for business combinations" as presented in our Statement of Consolidated Cash Flows for the year ended December 31, 2006.

Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

§ 2.0% of quarterly cash distributions up to $0.253 per unit;

§ 15.0% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and

§ 25.0% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $125.9 million, $107.4 million and $86.7 million to EPGP during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2007 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 45 days after the end of such fiscal quarter.

	Distribution per Unit	Record Date	Payment Date
2007			
1st Quarter	$ 0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$ 0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$ 0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$ 0.5000	Jan. 31, 2008	Feb. 7, 2008
2008			
1st Quarter	$ 0.5075	Apr. 30, 2008	May 7, 2008
2nd Quarter	$ 0.5150	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	$ 0.5225	Oct. 31, 2008	Nov. 12, 2008
4th Quarter	$ 0.5300	Jan. 30, 2009	Feb. 9, 2009

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) 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 accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	At December 31, 2008	At December 31, 2007
Commodity financial instruments – cash flow hedges (1)	$ (114,077)	$ (21,619)
Interest rate financial instruments – cash flow hedges (1)	3,818	34,980
Foreign currency cash flow hedges (1)	10,594	1,308
Foreign currency translation adjustment (2)	(1,301)	1,200
Pension and postretirement benefit plans (3)	(751)	588
Subtotal	(101,717)	16,457
Amount attributable to noncontrolling interest (4)	4,520	2,603
Total accumulated other comprehensive income (loss) in partners' equity	$ (97,197)	$ 19,060

(1) See Note 7 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 6 for additional information regarding pension and postretirement benefit plans.
(4) Represents the amount of accumulated other comprehensive loss allocated to noncontrolling interest based on the provisions of SFAS 160.

Noncontrolling Interest

Noncontrolling interest, as reflected on our December 31, 2008 and 2007 balance sheets, consists of $281.1 million and $288.6 million, respectively, attributable to third party owners of Duncan Energy Partners and the remainder to our other consolidated affiliates.

Net income attributable to noncontrolling interest for the year ended December 31, 2008 and 2007 includes $17.3 million and $13.9 million, respectively, attributable to third party owners of Duncan Energy Partners. The remaining net income attributable to noncontrolling interest amounts for 2008 and 2007 are attributable to our other consolidated affiliates.

Contributions from noncontrolling interest for the year ended December 31, 2007 include $290.5 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Note 16. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. 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 senior 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 consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, cumulative effect of changes in accounting principles, extraordinary charges and earnings attributable to noncontrolling interests. 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 intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity in earnings 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 stand alone 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 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 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. 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.

Historically, substantially all of our consolidated revenues were 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 and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction in progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets 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 Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100.0% of the gross operating margin amounts of Duncan Energy Partners.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

		For the Year Ended December 31,		
		2008	2007	2006
Revenues (1)		$ 21,905,656	$ 16,950,125	$ 13,990,969
Less:	Operating costs and expenses (1)	(20,460,964)	(16,009,051)	(13,089,091)
Add:	Equity in earnings of unconsolidated affiliates (1)	59,104	29,658	21,565
	Depreciation, amortization and accretion in operating costs and expenses (2)	555,370	513,840	440,256
	Operating lease expenses paid by EPCO (2)	2,038	2,105	2,109
	Loss (gain) from asset sales and related transactions in operating costs and expenses (2)	(3,735)	5,391	(3,359)
Total segment gross operating margin		$ 2,057,469	$ 1,492,068	$ 1,362,449

(1) These amounts are taken from our Statements of Consolidated Operations.

(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes and the cumulative effect of change in accounting principle follows:

	For the Year Ended December 31,		
	2008	2007	2006
Total segment gross operating margin	$ 2,057,469	$ 1,492,068	$ 1,362,449
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(555,370)	(513,840)	(440,256)
Operating lease expense paid by EPCO	(2,038)	(2,105)	(2,109)
Gain (loss) from asset sales and related transactions in operating costs and expenses	3,735	(5,391)	3,359
General and administrative costs	(90,550)	(87,695)	(63,391)
Operating income	1,413,246	883,037	860,052
Other expense, net	(391,448)	(303,463)	(229,967)
Income before provision for income taxes and the cumulative effect of change in accounting principle	$ 1,021,798	$ 579,574	$ 630,085

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	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Year ended December 31, 2008	$ 14,664,707	$ 3,161,014	$ 260,288	$ 2,683,197	$ --	$ 20,769,206
Year ended December 31, 2007	12,101,715	1,788,219	222,642	2,184,833	--	16,297,409
Year ended December 31, 2006	10,079,534	1,407,872	144,065	1,956,268	--	13,587,739
Revenues from related parties:						
Year ended December 31, 2008	717,244	411,084	8,122	--	--	1,136,450
Year ended December 31, 2007	369,654	281,876	1,169	17	--	652,716
Year ended December 31, 2006	110,409	291,023	1,798	--	--	403,230
Intersegment and intrasegment revenues:						
Year ended December 31, 2008	7,947,889	833,931	1,418	639,142	(9,422,380)	--
Year ended December 31, 2007	5,346,571	191,741	1,959	514,852	(6,055,123)	--
Year ended December 31, 2006	4,131,776	113,132	1,679	383,754	(4,630,341)	--
Total revenues:						
Year ended December 31, 2008	23,329,840	4,406,029	269,828	3,322,339	(9,422,380)	21,905,656
Year ended December 31, 2007	17,817,940	2,261,836	225,770	2,699,702	(6,055,123)	16,950,125
Year ended December 31, 2006	14,321,719	1,812,027	147,542	2,340,022	(4,630,341)	13,990,969
Equity in earnings of unconsolidated affiliates:						
Year ended December 31, 2008	1,430	22,959	33,609	1,106	--	59,104
Year ended December 31, 2007	6,031	9,540	12,628	1,459	--	29,658
Year ended December 31, 2006	5,715	2,872	11,909	1,069	--	21,565
Gross operating margin by individual business segment and in total:						
Year ended December 31, 2008	1,290,458	411,344	188,083	167,584	--	2,057,469
Year ended December 31, 2007	812,521	335,683	171,551	172,313	--	1,492,068
Year ended December 31, 2006	752,548	333,399	103,407	173,095	--	1,362,449
Segment assets:						
At December 31, 2008	5,424,134	4,033,312	1,394,480	698,157	1,604,691	13,154,774
At December 31, 2007	4,570,555	3,702,297	1,452,568	687,856	1,173,988	11,587,264
Investments in and advances to unconsolidated affiliates (see Note 11):						
At December 31, 2008	144,182	283,981	504,843	16,520	--	949,526
At December 31, 2007	117,089	239,327	484,588	17,335	--	858,339
Intangible assets, net (see Note 13):						
At December 31, 2008	351,010	333,462	116,219	54,725	--	855,416
At December 31, 2007	373,071	354,152	133,058	56,719	--	917,000
Goodwill (see Note 13):						
At December 31, 2008	268,938	282,121	82,135	73,690	--	706,884
At December 31, 2007	153,706	282,121	82,135	73,690	--	591,652

Our revenues are derived from a wide customer base. During 2008 our largest customer was LyondellBasell Industries ("LBI") and its affiliates, which accounted for 9.6% of our consolidated revenues. See Note 21 for additional information regarding our credit exposure to LBI's bankruptcy filing in January 2009. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and expenses for the periods noted:

	For the Year Ended December 31,		
	2008	2007	2006
NGL Pipelines & Services:			
Sales of NGLs	$ 14,680,607	$ 11,757,895	$ 9,442,403
Sales of other petroleum and related products	2,387	3,027	2,353
Midstream services	698,957	710,447	745,187
Total	15,381,951	12,471,369	10,189,943
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	3,091,296	1,481,569	1,103,169
Midstream services	480,802	588,526	595,726
Total	3,572,098	2,070,095	1,698,895
Offshore Pipelines & Services:			
Sales of natural gas	100	101	307
Sales of other petroleum and related products	11,144	12,086	4,562
Midstream services	257,166	211,624	140,994
Total	268,410	223,811	145,863
Petrochemical Services:			
Sales of other petroleum and related products	2,593,856	2,115,429	1,873,722
Midstream services	89,341	69,421	82,546
Total	2,683,197	2,184,850	1,956,268
Total consolidated revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969
Consolidated cost and expenses			
Operating costs and expenses:			
Cost of sales	$ 18,662,263	$ 14,509,220	$ 11,778,928
Depreciation, amortization and accretion	555,370	513,840	440,256
Loss (gain) on sale of assets and related transactions	(3,735)	5,391	(3,359)
Other operating costs and expenses	1,247,066	980,600	873,266
General and administrative costs	90,550	87,695	63,391
Total consolidated costs and expenses	$ 20,551,514	$ 16,096,746	$ 13,152,482

Note 17. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated.

	For the Year Ended December 31,		
	2008	2007	2006
Revenues from consolidated operations			
EPCO and affiliates	$ 121,201	$ 67,635	$ 98,671
Energy Transfer Equity and subsidiaries	618,370	294,441	--
Unconsolidated affiliates	396,879	290,640	304,559
Total	$ 1,136,450	$ 652,716	$ 403,230
Cost of sales			
EPCO and affiliates	$ 59,173	$ 33,827	$ 86,050
Energy Transfer Equity and subsidiaries	173,875	26,889	--
Unconsolidated affiliates	90,836	41,474	42,166
Total	$ 323,884	$ 102,190	$ 128,216
Operating costs and expenses			
EPCO and affiliates	$ 314,612	$ 260,716	$ 225,487
Energy Transfer Equity and subsidiaries	18,284	8,267	--
Unconsolidated affiliates	(10,388)	(8,709)	(10,560)
Total	$ 322,508	$ 260,274	$ 214,927
General and administrative expenses			
EPCO and affiliates	$ 59,058	$ 56,518	$ 41,265
Unconsolidated affiliates	(51)	--	--
Total	$ 59,007	$ 56,518	$ 41,265
Other income (expense)			
EPCO and affiliates	$ (274)	$ (170)	$ 680
Unconsolidated affiliates	--	--	262
Total	$ (274)	$ (170)	$ 942

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 private company subsidiaries;

§ EPGP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ TEPPCO, which is owned and controlled by Enterprise GP Holdings; and

§ the Employee Partnerships (see Note 5).

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 17.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2008, EPCO and its affiliates beneficially owned 152,506,527 (or 34.5%) of our outstanding common units, which includes 13,670,925 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100.0% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $144.1 million, $124.4 million and $101.8 million from us during the years ended December 31, 2008, 2007 and 2006, respectively. These amounts include incentive distributions of $125.9 million, $107.4 million and $86.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $405.2 million, $355.5 million and $306.5 million in cash distributions from us and Enterprise GP Holdings during the years ended December 31, 2008, 2007 and 2006, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

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. For the years ended December 31, 2008, 2007 and 2006, we paid this trucking affiliate $21.7 million, $17.5 million and $20.7 million, respectively, for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the years ended December 31, 2008, 2007 and 2006, we paid EPCO $5.3 million, $5.6 million and $3.0 million, respectively, for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition. For the nine months ended September 30, 2006, our revenues from this former unconsolidated affiliate were $55.8 million and our purchases were $43.4 million.

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. We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our 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 us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. 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. 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.

Our operating costs and expenses for the years ended December 31, 2008, 2007 and 2006 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. These reimbursements were $329.7 million, $273.0 million and $285.4 million during the years ended December 31, 2008, 2007 and 2006, respectively.

Likewise, our general and administrative costs for the years ended December 31, 2008, 2007 and 2006 include amounts we reimburse to EPCO for administrative services, including compensation of employees. 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 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). These reimbursements were $59.1 million, $56.5 million and $41.3 million during the years ended December 31, 2008, 2007 and 2006, respectively.

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

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), 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 Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts with respect to 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, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings 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

  § 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.

Enterprise GP Holdings 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 chief executive officer 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 chief executive officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, 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 Enterprise GP Holdings, as described above but utilizing EPGP's chief executive officer 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.

In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

§ If any business opportunity not covered by the preceding bullet point (i.e. not involving equity securities) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), 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 chief executive officer 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 chief executive officer 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, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings 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. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including TEPPCO GP) or their controlled affiliates. Likewise, TEPPCO (including TEPPCO GP) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us and Enterprise GP Holdings 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.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of our common units, Enterprise GP Holdings' units, or both. See Note 5 for additional information regarding the Employee Partnerships.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner.

We received $121.2 million, $67.6 million and $42.9 million from TEPPCO during the years ended December 31, 2008, 2007 and 2006, respectively, from the sale of hydrocarbon products. We paid TEPPCO $42.0 million, $19.4 million and $24.0 million for NGL pipeline transportation and storage services during the years ended December 31, 2008, 2007 and 2006, respectively.

Purchase of Pioneer I plant from TEPPCO. In March 2006, we paid TEPPCO $38.2 million for its Pioneer I natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to natural gas production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. TEPPCO has no continued involvement in the contracts or in the operations of the Pioneer facility.

Jonah Joint Venture with TEPPCO. In August 2006, we became a joint venture partner with TEPPCO in Jonah, which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO shared equally in the costs of the Phase V expansion, which is increased the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.4

Bcf/d and significantly reduced system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which has increased the system gathering capacity to 2.0 Bcf/d, was completed in July 2007 and the final phase of this expansion was completed in June 2008. We managed the Phase V construction project. Currently, the gathering capacity of this system is 2.4 Bcf/d.

Since August 1, 2006, we and TEPPCO have equally shared in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $306.5 million, which represents 50.0% of total Phase V costs incurred through December 31, 2008. We had a receivable of $1.0 million from TEPPCO at December 31, 2008 for Phase V expansion costs.

During the first quarter of 2008, Jonah initiated a separate project to increase gathering capacity on that portion of its system that serves the Pinedale production field. This new project is expected to increase overall capacity of the Jonah Gas Gathering System by an additional 0.2 Bcf/d. The total anticipated cost of this new project is $125.0 million, of which we will be responsible for our share of the construction costs.

TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50.0% of the incremental cash flow from portions of the system placed in service as part of the expansion. Since the first phase of this expansion was reached in July 2007, we and TEPPCO have shared earnings based on a formula that takes into account our respective capital contributions, including expenditures by TEPPCO prior to the expansion.

At December 31, 2008, we owned an approximate 19.4% interest in Jonah and TEPPCO owns 80.6%. We operate the Jonah system. We account for our investment in the Jonah joint venture using the equity method.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. The acquired pipelines became part of our Texas Intrastate System. The purchase of this asset was in accordance with the Board-approved management authorization policy.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million. This pipeline segment is part of the DEP South Texas NGL Pipeline System that commenced operations in January 2007. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area that is part of the DEP South Texas NGL Pipeline System. Although the primary term of the lease expired in September 2007, it was renewed on a month-to-month basis until construction of a parallel pipeline was completed in early 2008. These transactions were in accordance with the Board-approved management authorization policy.

Texas Offshore Port System Joint Venture. In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the expansion plans of Motiva and the acquisition of requisite permits.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and TEPPCO have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of December 31, 2008, our investment in the Texas Offshore Port System was $35.9 million.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the year ended December 31, 2008 and the eight months ended December 31, 2007, we recorded $618.4 million and $294.4 million, respectively, of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities. We incurred $192.2 million and $35.2 million in costs of sales and operating costs and expenses for the year ended December 31, 2008 and the eight months ended December 31, 2007, respectively. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

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 of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of 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 the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, 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 OLP, a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74.1% of Duncan Energy Partners' limited partner interests and 100.0% of its general partner.

DEP I Midstream Businesses

On February 5, 2007, EPO contributed a 66.0% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets (the "DEP I dropdown"). EPO retained the remaining 34.0% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene'), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL").

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its DEP I Revolving Credit Facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 14 for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses

On December 8, 2008, Duncan Energy Partners entered into the DEP II Purchase Agreement with EPO and Enterprise GTM, a wholly owned subsidiary of EPO. Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100.0% of the membership interests in Enterprise III from Enterprise GTM, thereby acquiring a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% membership interest in Enterprise Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction (the "DEP II dropdown"). Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under the DEP II Term Loan Agreement. See Note 14 for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102.0% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

Omnibus Agreement

On December 8, 2008, we entered into an amended and restated Omnibus Agreement with Duncan Energy Partners. The key provisions of this agreement are summarized as follows:

§ indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses we contributed to Duncan Energy Partners in connection with the respective dropdown transactions;

§ funding by EPO of 100.0% of post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of Duncan Energy Partners' initial public offering;

§ funding by EPO of 100.0% of post-December 8, 2008 capital expenditures (estimated at $1.4 million) to complete the Sherman Extension natural gas pipeline;

§ a right of first refusal to EPO in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and

§ a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and Duncan Energy Partners have also agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed.

Our general partner's ACG Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

EPO has indemnified Duncan Energy Partners against certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in connection with the DEP I and DEP II dropdown transactions. These liabilities include both known and unknown environmental and related liabilities. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage, and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

§ certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and

§ certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of its common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the ASA, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the ASA with EPO, EPCO and other affiliates of EPCO.

Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66.0% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $32.5 million and $9.9 million in connection with the Omnibus Agreement during the years ended December 31, 2008 and 2007, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement

The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100.0% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66.0% share of these projects from EPO within 90 days of such projects being placed in service.

EPO made cash contributions of $99.5 million and $38.1 million under the Caverns LLC Agreement during the years ended December 31, 2008 and 2007, respectively, to fund 100.0% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66.0% for Duncan Energy Partners and 34.0% for EPO. EPO expects to make additional contributions of approximately $27.5 million to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100.0% of the depreciation related to projects that it has fully funded.   For the two-month period in 2008 covered by the amendment, EPO was allocated depreciation expense of $1.0 million related to such projects.

The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

Company and Limited Partnership Agreements – DEP II Midstream Businesses

On December 8, 2007, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II dropdown transaction. Collectively, these amended and restated agreements provide for the following:

§ the acquisition by Enterprise III (a wholly owned subsidiary of Duncan Energy Partners) from Enterprise GTM (our wholly owned subsidiary) of a 66.0% general partner interest in Enterprise GC, a 51.0% general partner interest in Enterprise Intrastate and a 51.0% member interest in Enterprise Texas;

§ the payment of distributions in accordance with an overall "waterfall" approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98.0% to Enterprise GTM and 2.0% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102.0% of 11.85%, or 12.087%;

§ the funding of operating cash flow deficits in accordance with each owner's respective partner or member interest; and

§ the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100.0% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner's Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100.0% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 16 of the Notes to Consolidated Financial Statements for a discussion of this alignment of commercial interests. 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 $362.9 million, $268.0 million and $277.7 million for the years ended December 31, 2008, 2007 and 2006. In addition, Duncan Energy Partners furnished $1.0 million in letters of credit on behalf of Evangeline at December 31, 2008.

§ 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 $24.5 million, $17.3 million and $21.8 million for the years ended December 31, 2008, 2007 and 2006. Expenses with Promix were $38.7 million, $30.4 million and $34.9 million for the years ended December 31, 2008, 2007 and 2006.

§ We pay Jonah for natural gas purchases from its gathering system. Expenses with Jonah were $38.3 million and $4.9 million for the years ended December 31, 2008 and 2007. We were not entitled to our 19.4% interest in Jonah until July 2007.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $9.9 million, $9.3 million and $8.9 million for the years ended December 31, 2008, 2007 and 2006.

Note 18. 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 Franchise Tax in 2006, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Current:			
Federal	$ 4,922	$ 4,700	$ 7,694
State	19,350	3,871	1,148
Foreign	414	128	--
Total current	24,686	8,699	8,842
Deferred:			
Federal	760	2,784	6,109
State	928	3,774	6,372
Foreign	27	--	--
Total deferred	1,715	6,558	12,481
Total provision for income taxes	$ 26,401	$ 15,257	$ 21,323

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 the Year Ended December 31,		
	2008	**2007**	**2006**
Pre Tax Net Book Income (“NBI”)	$ 1,021,798	$ 579,574	$ 630,085
Revised Texas franchise tax	19,344	7,146	8,119
State income taxes (net of federal benefit)	505	325	(396)
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	6,305	5,318	13,347
Taxes charged to cumulative effect of change in accounting principle	--	--	(3)
Valuation allowance	(1,412)	2,347	123
Other permanent differences	1,659	121	133
Provision for income taxes	$ 26,401	$ 15,257	$ 21,323
Effective income tax rate	2.6 %	2.6 %	3.4 %

Significant components of deferred tax assets and deferred tax liabilities as of December 31, 2008 and 2007 are as follows:

	At December 31, 2008	At December 31, 2007
Deferred tax assets:		
Net operating loss carryovers	$ 26,311	$ 23,270
Property, plant and equipment	753	--
Credit carryover	26	26
Charitable contribution carryover	20	16
Employee benefit plans	2,631	3,214
Deferred revenue	964	642
Reserve for legal fees and damages	289	478
Equity investment in partnerships	596	409
AROs	76	80
Accruals	898	1,068
Total deferred tax assets	32,564	29,203
Valuation allowance	(3,932)	(5,345)
Net deferred tax assets	28,632	23,858
Deferred tax liabilities:		
Property, plant and equipment	92,899	40,520
Other	43	99
Total deferred tax liabilities	92,942	40,619
Total net deferred tax liabilities	$ (64,310)	$ (16,761)
Current portion of total net deferred tax assets	$ 1,397	$ 1,081
Long-term portion of total net deferred tax liabilities	$ (65,707)	$ (17,842)

We had net operating loss carryovers of $26.3 million and $23.3 million at December 31, 2008 and 2007, respectively. These losses expire in various years between 2009 and 2028 and are subject to limitations on their utilization. We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. The valuation allowance was $3.9 million and $5.3 million at December 31, 2008 and 2007, respectively, and serves to reduce the recognized tax benefit associated with carryovers of our corporate entities to an amount that will, more likely than not, be realized. The $1.4 million decrease in valuation allowance for 2008 is comprised primarily of a $1.6 million decrease for Canadian Enterprise Gas Products, Ltd.

We have deferred tax liabilities on property plant and equipment of $92.9 million and $40.5 million at December 31, 2008 and 2007, respectively. The increase in 2008 is comprised primarily of $45.1 million related to the difference in book and tax basis of property, plant and equipment resulting from the acquisition of the remaining equity interest of Dixie Pipeline. See Note 12 for additional information.

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, 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) 70.0% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the Revised Texas Franchise 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 Revised Texas Franchise Tax, we recorded a net deferred tax liability of $0.9 million and $3.8 million during the years ended December 31, 2008 and 2007, respectively. The offsetting net charge of $0.9 million and $3.8 million is shown on our Statements of Consolidated Operations for the years ended December 31, 2008 and 2007, respectively, as a component of “Provision for income taxes.”

Note 19. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss available to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss available to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, restricted units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss available to limited partner interests is net of our general partner's share of such earnings. The following table presents the net income available to EPGP for the periods indicated:

	For The Year Ended December 31,		
	2008	2007	2006
Net income attributable to Enterprise Products Partners L.P.	$ 954,021	$ 533,674	$ 601,155
Less incentive earnings allocations to EPGP	(125,912)	(107,421)	(86,710)
Net income available after incentive earnings allocation	828,109	426,253	514,445
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 16,562	$ 8,525	$ 10,289
Incentive earnings allocation to EPGP	$ 125,912	$ 107,421	$ 86,710
Standard earnings allocation to EPGP	16,562	8,525	10,289
Net income available to EPGP	142,474	115,946	96,999
Adjustment for EITF 07-4 (1)	5,278	4,500	6,023
Net income available to EPGP for EPU purposes	$ 147,752	$ 120,446	$ 103,022

(1) For purposes of computing basic and diluted earnings per unit, we used the provisions of EITF 07-4.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For The Year Ended December 31,		
	2008	2007	2006
BASIC EARNINGS PER UNIT			
Numerator			
Net income attributable to Enterprise Products Partners L.P.	$ 954,021	$ 533,674	$ 601,155
Net income available to EPGP for EPU purposes	(147,752)	(120,446)	(103,022)
Net income available to limited partners	$ 806,269	$ 413,228	$ 498,133
Denominator			
Common units	435,397	432,513	413,472
Time-vested restricted units	1,980	1,446	970
Total	437,377	433,959	414,442
Basic earnings per unit			
Net income per unit before EPGP earnings allocation	$ 2.18	$ 1.23	$ 1.45
Net income available to EPGP	(0.34)	(0.28)	(0.25)
Net income available to limited partners	$ 1.84	$ 0.95	$ 1.20
DILUTED EARNINGS PER UNIT			
Numerator			
Net income attributable to Enterprise Products Partners L.P.	$ 954,021	$ 533,674	$ 601,155
Net income available to EPGP for EPU purposes	(147,752)	(120,446)	(103,022)
Net income available to limited partners	$ 806,269	$ 413,228	$ 498,133
Denominator			
Common units	435,397	432,513	413,472
Time-vested restricted units	1,980	1,446	970
Performance-based restricted units	5	9	20
Incremental option units	200	459	297
Total	437,582	434,427	414,759
Diluted earnings per unit			
Net income per unit before EPGP earnings allocation	$ 2.18	$ 1.23	$ 1.45
Net income available to EPGP	(0.34)	(0.28)	(0.25)
Net income available to limited partners	$ 1.84	$ 0.95	$ 1.20

Note 20. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business 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 as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, results of operations or cash flows.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO.; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into certain 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; (ii) the sale by TEPPCO of its Pioneer natural gas processing plant to Enterprise Products Partners in March 2006; and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's IDRs in exchange for TEPPCO common 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) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 17 for additional information regarding our relationship with TEPPCO.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the U.S. Department of Justice ("DOJ") 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. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether ("MTBE"). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us 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 stormwater permit and appropriate stormwater plan. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. The State has not yet assessed penalties and we are unable to predict the amount of penalties that may be assessed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

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 as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 40.0% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws, and Marathon believes there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. The State seeks penalties above $100,000. Marathon continues to work with the State to determine if resolution of the case is possible.

Contractual Obligations

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

	Payment or Settlement due by Period													
Contractual Obligations		**Total**		**2009**		**2010**		**2011**		**2012**		**2013**		**Thereafter**
Scheduled maturities of long-term debt	$	9,046,046	$	--	$	554,000	$	934,250	$	1,517,596	$	750,000	$	5,290,200
Estimated cash payments for interest	$	9,351,928	$	544,658	$	522,633	$	471,253	$	451,450	$	369,673	$	6,992,261
Operating lease obligations	$	331,419	$	32,299	$	27,541	$	27,831	$	27,066	$	24,481	$	192,201
Purchase obligations:														
Product purchase commitments:														
Estimated payment obligations:														
Natural gas	$	5,225,141	$	323,309	$	515,102	$	635,000	$	660,626	$	487,984	$	2,603,120
NGLs	$	1,923,792	$	969,870	$	136,422	$	136,250	$	136,250	$	136,250	$	408,750
Petrochemicals	$	1,746,138	$	685,643	$	376,636	$	247,757	$	181,650	$	86,768	$	167,684
Other	$	37,455	$	19,202	$	3,459	$	3,322	$	3,051	$	2,919	$	5,502
Underlying major volume commitments:														
Natural gas (in BBtus)		981,955		56,650		93,150		115,925		120,780		93,950		501,500
NGLs (in MBbls)		56,622		23,576		4,726		4,720		4,720		4,720		14,160
Petrochemicals (in MBbls)		67,696		24,949		13,420		10,428		7,906		3,759		7,234
Service payment commitments	$	529,402	$	52,614	$	50,902	$	49,501	$	47,025	$	46,142	$	283,218
Capital expenditure commitments	$	521,262	$	521,262	$	--	$	--	$	--	$	--	$	--

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements such as the indentures governing EPO's senior notes and the credit agreement governing EPO's Multi-Year Revolving Credit Facility. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 14 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 an affiliate of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 2 to 28 years and include renewal options that could extend the agreements for up to an additional 20 years.

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, 2008, 2007 or 2006; however, we did incur $9.3 million of repair costs associated with our lease of an underground natural gas storage facility in 2006.

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 at our formation. EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2008, 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 2009 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 have 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 $36.0 million, $38.5 million and $39.3 million during the years ended December 31, 2008, 2007 and 2006, 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 NGLs, certain petrochemicals and natural gas 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, 2008 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2008, 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 such as equipment maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our 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 17). This includes costs associated with unit option awards granted to these employees to purchase our common units. At December 31, 2008, there were 2,168,500 and 795,000 unit options outstanding under the EPCO 1998 Plan and EPD 2008 LTIP, respectively, for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of unit option awards outstanding at December 31, 2008 was $26.32 and $30.93 per common unit under the EPCO 1998 Plan and EPD 2008 LTIP, respectively. At December 31, 2008, 548,500 of these unit options were exercisable under the EPCO 1998 Plan. An additional 365,000, 480,000 and 775,000 of these unit options will be exercisable in 2009, 2010 and 2012, respectively under the EPCO 1998 Plan. The 795,000 unit options outstanding under the EPD 2008 LTIP will become exercisable in 2013. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 5 for additional information regarding our accounting for equity awards.

Performance Guaranty

In December 2004, a subsidiary of ours entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement, as amended, obligated our subsidiary to construct the Independence Hub offshore platform and to process 1.0 Bcf/d of natural gas and condensate for the producers. We guaranteed to the producers the construction-related performance of our subsidiary up to an amount of $340.8 million. The performance guaranty expired during the second quarter of 2007.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2008, claims against us totaled approximately $15.4 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, if any, 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 (i) accrued as product payables on our Consolidated Balance Sheets, (ii) in transit for delivery to our customers or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our natural gas, NGL and petrochemical storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2008, NGL and petrochemical products aggregating 29.6 million barrels were due to be redelivered to their owners along with 18.5 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Note 21. 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, certain petrochemicals and crude oil. As such, our financial condition, 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. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations 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 transported, gathered or processed 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 and crude oil handled by our facilities.

A reduction in demand for NGL 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 NGLs, (iii) increased competition from petroleum-based 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.

Our revenues are derived from a wide customer base. During 2008 our largest customer was LBI and its affiliates, which accounted for 9.6% of our consolidated revenues. In 2007 and 2006, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9% and 6.1%, respectively, of our consolidated revenues.

On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

For 2008, LBI accounted for 10.2%, or $1.6 billion, of revenues attributable to our NGL Pipelines & Services business segment and 19.2%, or $516.2 million, of revenues attributable to our Petrochemical Services business segment.

Counterparty Risk with Respect to Financial Instruments

In those situations where we are exposed to credit risk in our financial 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.

Weather-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.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available.

Hurricane Ivan insurance claims. During the year ended December 31, 2008, we did not receive any reimbursements from insurance carriers related to property damage claims associated with this storm. During the year ended December 31, 2007, we received cash reimbursements from insurance carriers totaling $1.3 million, related to property damage claims. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. During the year ended December 31, 2008, we did not receive any proceeds from these claims. During the year ended December 31, 2007, we received $0.4 million of nonrefundable cash proceeds from such claims. We are continuing our efforts to collect residual balances from this storm. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as a gain in our Statements of Consolidated Operations in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. With respect to these storms, we have $30.5 million of estimated property damage claims outstanding at December 31, 2008, that we believe are probable of collection during the period 2009. We continue to pursue collection of our property damage claims related to these named storms. As of December 31, 2008, we had received all proceeds from our business interruption claims related to these storm events.

Hurricanes Gustav and Ike insurance claims. In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $47.9 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

Proceeds from Business Interruption and Property Damage Claims

The following table summarizes proceeds we received during the periods indicated from business interruption and property damage insurance claims with respect to certain named storms:

	For the Year Ended December 31,		
	2008	2007	2006
Business interruption proceeds:			
Hurricane Ivan	$ --	$ 377	$ 17,382
Hurricane Katrina	501	19,005	24,500
Hurricane Rita	662	14,955	22,000
Other	--	996	--
Total proceeds	1,163	35,333	63,882
Property damage proceeds:			
Hurricane Ivan	--	1,273	24,104
Hurricane Katrina	9,404	79,651	7,500
Hurricane Rita	2,678	24,105	3,000
Other	--	184	--
Total proceeds	12,082	105,213	34,604
Total	$ 13,245	$ 140,546	$ 98,486

At December 31, 2008, we have $39.0 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2009. In February 2009, we collected $20.8 million of the amounts outstanding. 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.

During 2008, we collected $0.2 million of business interruption proceeds that were not related to storm events.

Note 22. Supplemental Cash Flow Information

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

§ The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period. We employ prudent cash management practices and monitor our daily cash requirements to meet our ongoing liquidity needs.

§ If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges. From a receivables standpoint, we monitor the amount of credit extended to customers.

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

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

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 the Year Ended December 31,		
	2008	2007	2006
Decrease (increase) in:			
Accounts and notes receivable – trade	$ 744,277	$ (640,092)	$ 164,240
Accounts receivable – related party	16,494	(63,254)	(8,612)
Inventories	(15,425)	(14,051)	(66,288)
Prepaid and other current assets	(26,156)	41,266	14,261
Other assets	(2,910)	5,630	(22,581)
Increase (decrease) in:			
Accounts payable – trade	(18,372)	36,870	(1,509)
Accounts payable – related party	15,126	17,111	(10,769)
Accrued product payables	(1,080,034)	862,941	(8,344)
Accrued expenses	1,920	120,054	(62,963)
Accrued interest	20,902	40,107	19,671
Other current liabilities	(17,913)	37,248	74,206
Other liabilities	4,661	(2,524)	(7,894)
Net effect of changes in operating accounts	$ (357,430)	$ 441,306	$ 83,418
Cash payments for interest, net of $71,584, $75,476 and $55,660 capitalized in 2008, 2007 and 2006, respectively	$ 441,550	$ 325,339	$ 213,365
Cash payments for federal and state income taxes	$ 4,830	$ 5,760	$ 10,497

The following table provides supplemental cash flow information regarding business combinations we completed during the periods indicated. See Note 12, for additional information regarding our business combination transactions.

	For the Year Ended December 31,		
	2008	2007	2006
Assets acquired	$ 254,322	$ 37,037	$ 477,015
Less liabilities assumed	(52,162)	(1,244)	(19,403)
Net assets acquired	202,160	35,793	457,612
Less equity issued	--	--	(181,112)
Cash used for business combinations, net of cash received	$ 202,160	$ 35,793	$ 276,500

We incurred liabilities for construction in progress that had not been paid at December 31, 2008, 2007 and 2006 of $90.6 million, $95.5 million and $195.1 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. We received $25.8 million, $57.5 million and $60.5 million as contributions in aid of our construction costs during the years ended December 31, 2008, 2007 and 2006, respectively.

Note 23. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2008 and 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2008:				
Revenues	$ 5,684,535	$ 6,339,615	$ 6,297,902	$ 3,583,604
Operating income	366,732	374,270	319,116	353,128
Income before the cumulative effect of change in accounting principle	272,020	272,206	211,027	240,144
Net income	272,020	272,206	211,027	240,144
Net income attributable to Enterprise Products Partners L.P.	259,609	263,270	203,081	228,061
Earnings per unit before the cumulative effect of change in accounting principle:				
Basic	$ 0.51	$ 0.52	$ 0.38	$ 0.43
Diluted	$ 0.51	$ 0.52	$ 0.38	$ 0.43
Earnings per unit:				
Basic	$ 0.51	$ 0.52	$ 0.38	$ 0.43
Diluted	$ 0.51	$ 0.52	$ 0.38	$ 0.43
For the Year Ended December 31, 2007:				
Revenues	$ 3,322,854	$ 4,212,806	$ 4,111,996	$ 5,302,469
Operating income	187,924	214,562	210,830	269,721
Income before the cumulative effect of change in accounting principle	117,706	147,894	125,388	173,329
Net income	117,706	147,894	125,388	173,329
Net income attributable to Enterprise Products Partners L.P.	112,045	142,154	117,606	161,869
Earnings per unit before the cumulative effect of change in accounting principle:				
Basic	$ 0.19	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.19	$ 0.26	$ 0.20	$ 0.30
Earnings per unit:				
Basic	$ 0.19	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.19	$ 0.26	$ 0.20	$ 0.30

Note 24. Condensed Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of the Dixie revolving credit facility (terminated January 2009) and the Duncan Energy Partners' debt obligations. 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. See Note 14 for additional information regarding our consolidated debt obligations.

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	At December 31, 2008	At December 31, 2007
ASSETS		
Current assets	$ 2,175,555	$ 2,545,297
Property, plant and equipment, net	13,154,774	11,587,264
Investments in and advances to unconsolidated affiliates, net	949,526	858,339
Intangible assets, net	855,416	917,000
Goodwill	706,884	591,652
Other assets	126,619	115,458
Total	$ 17,968,774	$ 16,615,010
LIABILITIES AND EQUITY		
Current liabilities	$ 2,222,650	$ 3,044,002
Long-term debt	9,108,410	6,906,145
Other long-term liabilities	147,339	95,112
Equity	6,490,375	6,569,751
Total	$ 17,968,774	$ 16,615,010
Total EPO debt obligations guaranteed Enterprise Products Partners L.P.	$ 8,561,796	$ 6,686,500

The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Year Ended December 31, 2008	2007	2006
Revenues	$ 21,905,656	$ 16,950,125	$ 13,990,969
Costs and expenses	20,549,026	16,094,248	13,148,530
Equity in earnings of unconsolidated affiliates	59,104	29,658	21,565
Operating income	1,415,734	885,535	864,004
Other expense	(391,457)	(305,236)	(231,876)
Income before provision for income taxes and the cumulative effect of change in accounting principle	1,024,277	580,299	632,128
Provision for income taxes	(26,376)	(15,317)	(21,198)
Income before the cumulative effect of change in accounting principle	997,901	564,982	610,930
Cumulative effect of change in accounting principle	--	--	1,472
Net income	997,901	564,982	612,402
Net income attributable to noncontrolling interest	(41,638)	(30,737)	(9,190)
Net income attributable to EPO	$ 956,263	$ 534,245	$ 603,212

Note 25. Subsequent Events

In January 2009, we sold 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit. We used the net offering proceeds of $225.6 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.

Item 15. ***Exhibits and Financial Statement Schedules.***

Exhibit Number	Exhibit
12.1	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2008, 2007, 2006, 2005 and 2004.

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	For the Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Consolidated income	$ 995,397	$ 564,317	$ 610,234	$ 425,268	$ 276,389
Add: Provision for income taxes	26,401	15,257	21,323	8,362	3,761
Less: Equity in earnings from unconsolidated affiliates	(59,104)	(29,658)	(21,565)	(14,548)	(52,787)
Consolidated pre-tax income before equity in income of unconsolidated affiliates	962,694	549,916	609,992	419,082	227,363
Add: Fixed charges	484,259	400,065	306,791	264,921	168,463
Amortization of capitalized interest	10,486	9,335	7,894	1,644	974
Distributed income of equity investees	98,553	73,593	43,032	56,058	68,027
Subtotal	1,555,992	1,032,909	967,709	741,705	464,827
Less: Capitalized interest	(71,584)	(75,476)	(55,660)	(22,046)	(2,766)
Net income attributable to noncontrolling interest	(41,376)	(30,643)	(9,079)	(5,760)	(8,128)
Total earnings	$ 1,443,032	$ 926,790	$ 902,970	$ 713,899	$ 453,933
Fixed charges:					
Interest expense	$ 400,686	$ 311,764	$ 238,023	$ 230,549	$ 155,740
Capitalized interest	71,584	75,476	55,660	22,046	2,766
Interest portion of rental expense	11,989	12,825	13,108	12,326	9,957
Total	$ 484,259	$ 400,065	$ 306,791	$ 264,921	$ 168,463
Ratio of earnings to fixed charges	2.98x	2.32x	2.94x	2.69x	2.69x

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 before 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
- § net income attributable to 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 expenses; and preference dividend requirements of consolidated subsidiaries.

Enterprise Products GP, LLC

Consolidated Balance Sheet at December 31, 2008
and Report of Independent Registered Public Accounting Firm

ENTERPRISE PRODUCTS GP, LLC
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC
Houston, Texas

We have audited the accompanying consolidated balance sheet of Enterprise Products GP, LLC and subsidiaries (the "Company") at December 31, 2008. This consolidated financial statement is the responsibility of the Company's management. Our responsibility is to express an opinion on this consolidated financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. 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 consolidated balance sheet presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated balance sheet presents fairly, in all material respects, the financial position of the Company at December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 3 to the consolidated balance sheet, the accompanying consolidated balance sheet has been retrospectively adjusted for the adoption of FASB Statement No. 160, "*Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51*" ("SFAS 160").

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 2, 2009
(July 6, 2009 as to the effects of the adoption of SFAS 160 and the related disclosures in Notes 1 and 3)

ENTERPRISE PRODUCTS GP, LLC
CONSOLIDATED BALANCE SHEET
AT DECEMBER 31, 2008
(Dollars in thousands)

ASSETS	
Current assets:	
Cash and cash equivalents	$ 35,486
Restricted cash	203,789
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $15,123	1,185,515
Accounts receivable – related parties	57,602
Inventories	362,815
Derivative assets	202,826
Prepaid and other current assets	111,773
Total current assets	2,159,806
Property, plant and equipment, net	13,154,774
Investments in and advances to unconsolidated affiliates	953,541
Intangible assets, net of accumulated amortization of $429,872	855,416
Goodwill	706,884
Deferred tax asset	355
Other assets	126,860
Total assets	$ 17,957,636
LIABILITIES AND EQUITY	
Current liabilities:	
Accounts payable – trade	$ 300,532
Accounts payable – related parties	39,603
Accrued product payables	1,142,370
Accrued expenses	48,772
Accrued interest	151,873
Derivative liabilities	287,161
Other current liabilities	252,892
Total current liabilities	2,223,203
Long-term debt: (see Note 12)	
Senior debt obligations – principal	7,813,346
Junior subordinated notes – principal	1,232,700
Other	62,364
Total long-term debt	9,108,410
Deferred tax liabilities	66,060
Other long-term liabilities	81,374
Commitments and contingencies	
Equity: (see Note 13)	
Member's interest	526,671
Accumulated other comprehensive loss	(2,005)
Total member's equity	524,666
Noncontrolling interest	5,953,923
Total equity	6,478,589
Total liabilities and equity	$ 17,957,636

See Notes to Consolidated Balance Sheet.

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1. Company Organization

Company Organization

Enterprise Products GP, LLC is a Delaware limited liability company that was formed in April 1998 to become the general partner of Enterprise Products Partners L.P. The business purpose of Enterprise Products GP, LLC is to manage the affairs and operations of Enterprise Products Partners L.P. At December 31, 2008, Enterprise GP Holdings L.P. owned 100% of the membership interests of Enterprise Products GP, LLC.

Unless the context requires otherwise, references to "we," "us," "our" or "the Company" are intended to mean and include the business and operations of Enterprise Products GP, LLC, as well as its consolidated subsidiaries, which include Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to "Enterprise Products Partners" mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise Products Partners is a publicly traded Delaware limited partnership, the registered common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." References to "EPGP" mean Enterprise Products GP, LLC, individually as the general partner of Enterprise Products Partners, and not on a consolidated basis. Enterprise Products Partners has no business activities outside those conducted by its operating subsidiary, Enterprise Products Operating LLC ("EPO"). Enterprise Products Partners and EPO were formed to acquire, own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc.

References to "Enterprise GP Holdings" mean the business and operations of Enterprise GP Holdings L.P. and its consolidated subsidiaries. Enterprise GP Holdings is a publicly traded Delaware limited partnership, the registered units of which are listed on the NYSE under the ticker symbol "EPE." References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired noncontrolling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

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, which are private company affiliates of EPCO, Inc.

On February 5, 2007, a consolidated subsidiary of EPO, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 15). Duncan Energy Partners owns equity interests in certain of the midstream energy businesses 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 a wholly owned subsidiary of EPO.

References to "EPCO" mean EPCO, Inc. and its wholly-owned private company affiliates, which are related parties to all of the foregoing named entities. Dan L. Duncan is the Group Co-Chairman and controlling shareholder of EPCO.

For financial reporting purposes, Enterprise Products Partners consolidates the balance sheet of Duncan Energy Partners with that of its own. Enterprise Products Partners controls Duncan Energy Partners through the ownership of its general partner. Public ownership of Duncan Energy Partners' net assets is presented as a component of noncontrolling interest in our Consolidated Balance Sheet. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners nor EPGP have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

EPGP owns a 2% general partner interest in Enterprise Products Partners, which conducts substantially all of its business. EPGP has no independent operations and no material assets outside those of Enterprise Products Partners. The number of reconciling items between our consolidated balance sheet and that of Enterprise Products Partners are few. The most significant difference is that relating to noncontrolling interest ownership in our net assets by the limited partners of Enterprise Products Partners, and the elimination of our investment in Enterprise Products Partners with our underlying partner's capital account in Enterprise Products Partners. See Note 13 for additional information regarding noncontrolling interest in our consolidated subsidiaries.

Effective January 1, 2009, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51. SFAS 160 established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our Consolidated Balance Sheet. The presentation and disclosure requirements of SFAS 160 have been applied retrospectively to the Consolidated Balance Sheet and Notes included in this Current Report on Form 8-K

Note 2. General Accounting Policies and Related Matters

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 year ended December 31, 2008:

Balance at beginning of period	$ 21,659
Charges to expense	1,098
Deductions	(7,634)
Balance at end of period	$ 15,123

See “Credit Risk Due to Industry Concentrations” in Note 18 for more 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 Balance Sheet includes our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material 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 balance sheet of such businesses with those of our own.

We consolidate the balance sheet of Enterprise Products Partners with that of EPGP. This accounting consolidation is required because EPGP owns 100% of the general partnership interest in Enterprise Products Partners, which gives EPGP the ability to exercise control over Enterprise Products Partners.

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 are material and 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. We currently do not have any investments accounted for 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 Sheet, all components of current assets and current liabilities that exceed 5% of total current assets and liabilities, respectively.

Employee Benefit Plans

In 2005, we acquired a controlling ownership interest in Dixie Pipeline Company ("Dixie"), which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans.

SFAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of SFAS 87, 88, 106, and 132(R), requires businesses to record the over-funded or under-funded status of defined benefit pension and other postretirement plans as an asset or liability at a measurement date and to recognize annual changes in the funded status of each plan through other comprehensive income (loss). At December 31, 2006, Dixie adopted the provisions of SFAS 158. See Note 5 for additional information regarding Dixie's employee benefit plans.

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, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability for remediation costs associated with mercury gas meters. The balance of this environmental liability was $6.3 million at December 31, 2008. At December 31, 2008, total reserves for environmental liabilities, including those related to the mercury gas meters, were $15.4 million. At December 31, 2008, $2.8 million of these amounts are classified as current liabilities.

In February 2007, we reserved $6.5 million in cash we received from a third party to fund anticipated environmental remediation costs. These expected costs are associated with assets acquired in connection with the GulfTerra Merger. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification arrangement was terminated.

The following table presents the activity of our environmental reserves for the year ended December 31, 2008:

Balance at beginning of period	$	26,459
Charges to expense		905
Acquisition-related additions and other		--
Deductions		(12,002)
Balance at end of period	$	15,362

Equity Awards

See Note 4 for information regarding our accounting for equity awards.

Estimates

Preparing our financial statements in conformity with generally accepted accounting principles in the United States ("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.

We revised the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System, effective January 1, 2008. This revision adjusted the remaining useful life of such assets to incorporate recent data showing that proved 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 at January 1, 2008. For additional information regarding this change in estimate, see Note 8.

Exchange Contracts

Exchanges are contractual agreements for the movements of 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, and 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.

Financial Instruments

We use financial 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. We recognize these transactions as assets or liabilities on our Consolidated Balance Sheet based on the instrument's fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period (i.e., using mark-to-market accounting) unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income (loss), which is generally referred to as "AOCI." Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income (loss) to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings. See Note 6 for additional information regarding our financial instruments.

Foreign Currency Translation

We own a 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 income (loss) in the accompanying Consolidated Balance Sheet. 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 hedging of currency risk.

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. We have not recognized any impairment losses related to goodwill for the period presented. See Note 11 for additional information regarding our goodwill.

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 in accordance with SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. 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.

No asset impairment charges were recorded in 2008.

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 earnings to adjust the carrying value of the investment to its estimated fair value.

We had no such impairment charges during the year ended December 31, 2008. See Note 9 for additional information regarding our equity method investments.

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, 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.

In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its pre-existing franchise tax, which applied to corporations and limited liability companies, to include limited partnerships and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas changed from non-taxable to taxable.

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.

In accordance with Financial Accounting Standards Board Interpretation 48, Accounting for Uncertainty in Income Taxes, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position. See Note 16 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of NGLs, certain petrochemical products and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges directly related to volumes we purchase from third parties or take title to in connection with processing or other agreements. As these volumes are sold and delivered out of inventory, the average cost of these products (including freight-in charges that have been capitalized) 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 <TABLE><CAPTION> 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 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 on-going 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 is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008, our natural gas imbalance receivables, net of allowance for doubtful accounts, were $48.4 million and are reflected as a component of "Accounts and notes receivable – trade" on our Consolidated Balance Sheet. At December 31, 2008, our imbalance payables were $40.7 million and are reflected as a component of "Accrued product payables" on our Consolidated Balance Sheet.

Noncontrolling Interest

As presented in our Consolidated Balance Sheet, noncontrolling interest represents third-party and affiliate ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our controlled subsidiaries, including Duncan Energy Partners, are consolidated with those of our own, with any third-party or affiliate ownership interests in such amounts presented as noncontrolling interest. See Note 13 for additional information regarding noncontrolling interest.

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, the following: (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, including a change in depreciation expense beginning January 1, 2008 resulting from a change in the estimated useful life of certain assets.

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 financial instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. During 2008, virtually all proceeds from the Petal GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The following table presents the components of our restricted cash balances at December 31, 2008:

Amounts held in brokerage accounts related to		
commodity hedging activities and physical natural gas purchases	$	203,789
Proceeds from Petal GO Zone bonds reserved for construction costs		1
Total restricted cash	$	203,790

Note 3. Recent Accounting Developments

The accounting standard setting bodies have recently issued the following accounting guidance that will affect our future financial statements: SFAS 141(R), Business Combinations; FASB Staff Position ("FSP") SFAS 142-3, Determination of the Useful Life of Intangible Assets; SFAS 157, Fair Value Measurements; SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51; SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133; and Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations.

SFAS 141(R), Business Combinations. SFAS 141(R) replaces SFAS 141, Business Combinations and was effective January 1, 2009. SFAS 141(R) retains the fundamental requirements of SFAS 141 in that the acquisition method of accounting (previously termed the "purchase method") be used for all business combinations and for the "acquirer" to be identified in each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. SFAS 141(R) will have an impact on the way in which we evaluate acquisitions.

The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

§ Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.

§ Recognizes and measures any goodwill acquired in the business combination or a gain resulting from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in net income as a gain attributable to the acquirer.

§ Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder's fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price.

FSP FAS 142-3, Determination of the Useful Life of Intangible Assets. FSP 142-3 revised the factors that should be considered in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our Consolidated Balance Sheet.

SFAS 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009. See Note 6 for information regarding fair value-related disclosures required for 2008 in connection with SFAS 157.

SFAS 157 applies to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies are required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Our adoption of this guidance is not expected to have a material impact on our Consolidated Balance Sheet. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB 51. SFAS 160 established accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior accounting literature. SFAS 160 was effective January 1, 2009. A noncontrolling interest is that portion of equity in a consolidated subsidiary not attributable, directly or indirectly, to a reporting entity. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity, including accumulated other comprehensive income, on the balance sheet (i.e., elimination of the "mezzanine" presentation); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income and other comprehensive income be allocated between the reporting entity and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests.

Effective January 1, 2009, we adopted the provisions of SFAS 160. The presentation and disclosure requirements of SFAS 160 have been applied retrospectively to the Consolidated Balance Sheet and Notes included in this Current Report on Form 8-K.

SFAS 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of SFAS 133. SFAS 161 revised the disclosure requirements for financial instruments and related hedging activities to provide users of financial statements with an enhanced understanding of (i) why and how an entity uses financial instruments, (ii) how an entity accounts for financial instruments and related hedged items under SFAS 133, Accounting for Derivative Instruments and Hedging Activities (including related interpretations), and (iii) how financial instruments and related hedged items affect an entity's financial position.

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

EITF 08-6, Equity Method Investment Accounting Considerations. EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments under SFAS 141(R) and SFAS 160. EITF 08-6 generally requires that (i) transaction costs should be included in the initial carrying value of an equity method investment; (ii) an equity method investor shall not test separately an investee's underlying assets for impairment, rather such testing should be performed in accordance with Opinion 18 (i.e., on the equity method investment itself); (iii) an equity method investor shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment (any gain or loss to the investor resulting from the investee's share issuance shall be recognized in earnings); and (iv) a gain or loss should not be recognized when changing the method of accounting for an investment from the equity method to the cost method. EITF 08-6 was effective January 1, 2009.

Note 4. Accounting for Equity Awards

We account for equity awards in accordance with SFAS 123(R), Share-Based Payment. SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other equity awards is estimated using the Black-Scholes option pricing model. The fair value of an equity-classified award (such as 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 (such as 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.

As used in the context of the EPCO plans, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

EPCO 1998 Plan

Unit option awards. Under the EPCO 1998 Long-Term Incentive Plan ("EPCO 1998 Plan"), non-qualified incentive options to purchase a fixed number of Enterprise Products Partners' common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, we amended the terms of certain of our 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 obligations under the EPCO 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from Enterprise Products Partners. When employees exercise unit options, we reimburse 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 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.

The EPCO 1998 Plan provides for the issuance of up to 7,000,000 of Enterprise Products Partners' common units. After giving effect to outstanding option awards at December 31, 2008 and the issuance and forfeiture of restricted unit awards through December 31, 2008, a total of 814,674 additional common units could be issued under the EPCO 1998 Plan.

The following table presents option activity under the EPCO 1998 Plan for the year ended December 31, 2008:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2007 (2)	2,315,000	$ 26.18		
Exercised	(61,500)	$ 20.38		
Forfeited	(85,000)	$ 26.72		
Outstanding at December 31, 2008 (3)	2,168,500	$ 26.32	5.19	$ --
Options exercisable at:				
December 31, 2008 (3)	548,500	$ 21.47	4.08	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) During 2008, we amended the terms of certain of Enterprise Products Partners' outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.
(3) We were committed to issue 2,168,500 of Enterprise Products Partners' common units at December 31, 2008 if all outstanding options awarded under the EPCO 1998 Plan (as of these dates) were exercised. An additional 365,000, 480,000 and 775,000 of these options are exercisable in 2009, 2010 and 2012, respectively.

The total intrinsic value of option awards exercised during the year ended December 31, 2008, was $0.6 million.

During the year ended December 31, 2008, we received cash of $0.7 million from the exercise of option awards granted under the EPCO 1998 Plan. Conversely, our option-related reimbursements to EPCO were $0.6 million.

Restricted unit awards. Under the EPCO 1998 Plan, we may also issue Enterprise Products Partners' restricted common units to key employees of EPCO and directors of EPGP. In general, Enterprise Products Partners' restricted unit awards allow recipients to acquire the underlying common units at no cost to the recipient once a defined cliff vesting period expires, subject to certain forfeiture provisions. The restrictions on such units generally lapse four years from the date of grant. Fair value of such restricted units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures.

The following table summarizes information regarding Enterprise Products Partners' restricted unit awards for the year ended December 31, 2008:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2007	1,688,540	
Granted (2)	766,200	$ 24.93
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Aggregate grant date fair value of restricted unit awards issued during 2008 was $19.1 million based on grant date market prices of Enterprise Products Partners' common units ranging from $25.00 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of restricted unit awards that vested during the year ended December 31, 2008 was $6.6 million.

Phantom unit awards. The EPCO 1998 Plan also provides for the issuance of Enterprise Products Partners' phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of Enterprise Products Partners' common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is four years from the date the award is granted. No phantom unit awards have been issued to date under the EPCO 1998 Plan.

The EPCO 1998 Plan also provides for the award of distribution equivalent rights ("DERs") in tandem with its phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by Enterprise Products Partners to its unitholders. No DERs have been issued as of December 31, 2008 under the EPCO 1998 Plan.

EPD 2008 LTIP

On January 29, 2008, Enterprise Products Partners' unitholders approved the Enterprise Products 2008 Long-Term Incentive Plan ("EPD 2008 LTIP"), which provides for awards of Enterprise Products Partners' common units and other rights to its non-employee directors and to consultants and employees of EPCO and its affiliates providing services to Enterprise Products Partners. Awards under the EPD 2008 LTIP may be granted in the form of Enterprise Products Partners' unit options, restricted units, phantom units, UARs and DERs. The EPD 2008 LTIP is administered by EPGP's Audit, Conflicts and Governance ("ACG") Committee. The EPD 2008 LTIP provides for the issuance of up to 10,000,000 of Enterprise Products Partners' common units. After giving effect to option awards outstanding at December 31, 2008, a total of 9,205,000 additional common units could be issued under the EPD 2008 LTIP.

The EPD 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of Enterprise Products Partners' unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The EPD 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Unit option awards. The exercise price of unit options awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of Enterprise Products Partners' common units at the date of grant. The following table presents unit option activity under the EPD 2008 LTIP for the period indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at January 1, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at December 31, 2008 (2)	795,000	$ 30.93	5.00

(1) Aggregate grant date fair value of these unit options issued during 2008 was $1.6 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%; (v) expected unit price volatility on Enterprise Products Partners' common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.
(2) The 795,000 units outstanding at December 31, 2008 will become exercisable in 2013.

At December 31, 2008, there was an estimated $1.3 million of total unrecognized compensation cost related to nonvested unit options granted under the EPD 2008 LTIP. We expect to recognize our share of this cost over a remaining period of 3.4 years in accordance with the ASA.

Phantom unit awards. The EPD 2008 LTIP also provides for the issuance of Enterprise Products Partners' phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of Enterprise Products Partners' common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is three years from the date the award is granted. There were a total of 4,400 phantom units granted under the EPD 2008 LTIP during the fourth quarter of 2008 and outstanding at December 31, 2008. These awards cliff vest in 2011. At December 31, 2008, we had an accrued liability of $5 thousand for compensation related to these phantom unit awards.

Employee Partnerships

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 five limited partnerships. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without capital contributions. As discussed and defined above, the Employee Partnerships are: EPE Unit I; EPE Unit II; EPE Unit III; Enterprise Unit; and EPCO Unit. Enterprise Unit and EPCO Unit were formed in 2008.

The Class B limited partner interests entitle each holder to participate in the appreciation in value of the publicly traded limited partner units owned by the underlying Employee Partnership. The Employee Partnerships own either Enterprise GP Holdings units ("EPE units") or Enterprise Products Partners' common units ("EPD units") or both. The Class B limited partner interests are subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements and upon certain change of control events.

We account for the profits interest awards under SFAS 123(R). As a result, the compensation expense attributable to these awards is based on the estimated grant date fair value of each award. An allocated portion of the fair value of these equity-based awards is charged to us under the ASA (see Note 15). We are not responsible for reimbursing EPCO for any expenses of the Employee Partnerships, including the value of any contributions of cash or limited partner units made by private company affiliates of EPCO at the formation of each Employee Partnership. However, pursuant to the ASA, beginning in

February 2009 we will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit.

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 any 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 following table summarizes key elements of each Employee Partnership as of December 31, 2008:

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Award Vesting Date (1)	Grant Date Fair Value of Awards (2)
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725% (3)	November 2012	$17.0 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725% (3)	February 2014	$0.3 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	May 2014	$32.7 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2014	$4.2 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	November 2013	$7.2 million

(1) The vesting date may be accelerated for change of control and other events as described in the underlying partnership agreements.
(2) Our estimated grant date fair values were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. See following table for information regarding our fair value assumptions.
(3) In July 2008, the Class A preferred return was reduced from 6.25% to the floating amounts presented.

The following table summarizes the assumptions we used in deriving the estimated grant date fair value for each of the Employee Partnerships using a Black-Scholes option pricing model:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield of EPE/EPD units	Expected Unit Price Volatility of EPE/EPD units
EPE Unit I	3 to 5 years	2.7% to 5.0%	3.0% to 4.8%	16.6% to 30.0%
EPE Unit II	5 to 6 years	3.3% to 4.4%	3.8% to 4.8%	18.7% to 19.4%
EPE Unit III	4 to 6 years	3.2% to 4.9%	4.0% to 4.8%	16.6% to 19.4%
Enterprise Unit	6 years	2.7% to 3.9%	4.5% to 8.0%	15.3% to 22.1%
EPCO Unit	5 years	2.4%	11.1%	50.0%

DEP GP UARs

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, Enterprise GP Holdings, Duncan Energy Partners or Enterprise Products Partners. These UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date fair value. If a director resigns prior to vesting, his UAR awards are forfeited. These UARs are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of December 31, 2008, a total of 90,000 UARs had been granted to non-employee directors of DEP GP that cliff vest in 2012. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings' unit price of $36.68.

Note 5. Employee Benefit Plans

Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, our discussion is limited to the following:

Defined Contribution Plan

Dixie contributed $0.3 million to its company-sponsored defined contribution plan for the year ended December 31, 2008.

Pension and Postretirement Benefit Plans

Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's postretirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table presents Dixie's benefit obligations, fair value of plan assets and funded status at December 31, 2008.

	Pension Plan	Postretirement Plan
Projected benefit obligation	$ 7,733	$ 4,976
Accumulated benefit obligation	5,711	--
Fair value of plan assets	4,035	--
Funded status	(3,698)	(4,976)

Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2008 were as follows: discount rate of 6.4%; rate of compensation increase of 4.0% for both the pension and postretirement plans; and a medical trend rate of 8.5% for 2009 grading to an ultimate trend of 5.0% for 2015 and later years.

Future benefits expected to be paid from Dixie's pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	Postretirement Plan
2009	$ 289	$ 357
2010	334	399
2011	535	427
2012	408	440
2013	775	439
2014 through 2018	4,211	2,067
Total	$ 6,552	$ 4,129

Included in accumulated other comprehensive loss on the Consolidated Balance Sheet at December 31, 2008 are the following amounts that have not been recognized in net periodic pension costs (in millions):

Unrecognized transition obligation	$ 0.9
Net of tax	0.5
Unrecognized prior service cost credit	(1.0)
Net of tax	(0.6)
Unrecognized net actuarial loss	1.3
Net of tax	0.8

Note 6. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt obligations and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates. See Note 12 for information regarding our consolidated debt obligations.

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

The following table provides additional information regarding derivative instruments as presented in our Consolidated Balance Sheet at December 31, 2008:

Current assets:		
Derivative assets:		
Interest rate risk hedging portfolio	$	7,780
Commodity risk hedging portfolio		185,762
Foreign currency risk hedging portfolio		9,284
Total derivative assets – current	$	202,826
Other assets:		
Interest rate risk hedging portfolio	$	38,939
Total derivative assets – long-term	$	38,939
Current liabilities:		
Derivative liabilities:		
Interest rate risk hedging portfolio	$	5,910
Commodity risk hedging portfolio		281,142
Foreign currency risk hedging portfolio		109
Total derivative liabilities – current	$	287,161
Other liabilities:		
Interest rate risk hedging portfolio	$	3,889
Commodity risk hedging portfolio		233
Total derivative liabilities – long-term	$	4,122

The following information summarizes the principal elements of our interest rate risk, commodity risk and foreign currency risk hedging portfolios. For amounts recorded on our balance sheet related to our consolidated hedging activities, please refer to the preceding table.

Interest Rate Risk Hedging Portfolio

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – EPO interest rate swaps

We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. At December 31, 2008, Enterprise Products Partners had four interest rate swap agreements outstanding having an aggregate notional value of $400.0 million that were accounted for as fair value hedges. The aggregate fair value of these interest rate swaps at December 31, 2008, was $46.7 million (an asset), with an offsetting increase in the fair value of the underlying debt.

The following table summarizes Enterprise Products Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Fixed Rate Debt	**Number of Swaps**	**Period Covered by Swap**	**Termination Date of Swap**	**Fixed to Variable Rate** (1)	**Notional Value**
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.015%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	3	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 5.297%	$300.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt.

Cash flow hedges - Duncan Energy Partners' interest rate swaps

At December 31, 2008, Duncan Energy Partners had interest rate swap agreements outstanding having an aggregate notional value of $175.0 million. These swaps were accounted for as cash flow hedges. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to the variable interest rates charged under its revolving credit facility. The aggregate fair value of these interest rate swaps at December 31, 2008 was a liability of $9.8 million.

The following table summarizes Duncan Energy Partners' interest rate swaps outstanding at December 31, 2008.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
DEP I Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

Commodity Risk Hedging Portfolio

Our commodity risk hedging portfolio was impacted by a significant decline in natural gas prices during the second half of 2008. As a result of the global recession, commodity prices have continued to be volatile during the first quarter of 2009. We may experience additional losses related to our commodity risk hedging portfolio in 2009.

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of its inventory positions. The commodity financial instruments we utilize are settled in cash.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with its NGL and petrochemical operations.

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at December 31, 2008 was $203.8 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our natural gas hedge positions.

Natural gas marketing activities

At December 31, 2008, the aggregate fair value of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $6.5 million. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for using mark-to-market accounting, with a small number accounted for as cash flow hedges. We did not have any cash flow hedges related to our natural gas marketing activities at December 31, 2008.

NGL and petrochemical operations

At December 31, 2008, the aggregate fair value of those financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $102.1 million. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting.

We have employed a program to economically hedge a portion of our earnings from natural gas processing in the Rocky Mountain region. This program consists of (i) the forward sale of a portion of our expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase, using commodity financial instruments, of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At December 31, 2008, this hedging program had hedged future expected gross margins (before plant operating expenses) of $483.9 million on 22.5 million barrels of forecasted NGL forward sales transactions extending through 2009.

Our NGL forward sales contracts are not accounted for as financial instruments under SFAS 133 since they meet normal purchase and sale exception criteria; therefore, changes in the aggregate economic value of these sales contracts are not reflected in net income and other comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into net income in that period.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a commodity financial instrument, we recognize an unrealized loss in other comprehensive loss for the excess of the natural gas price stated in the hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we pay for PTR, which would then be based on the lower market price. Conversely, if the market price of natural gas is greater than the price stipulated in such hedges, we recognize an unrealized gain in other comprehensive income for the excess of the market price over the natural gas price stated in the PTR hedge. If realized, the gains on the financial instrument would serve to reduce the actual cost paid for PTR, which would then be based on the higher market price. The net effect of these hedging relationships is that our total cost of natural gas used for PTR approximates the amount originally hedged under this program.

Foreign Currency Hedging Portfolio

We are exposed to foreign currency exchange rate risk primarily through a Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month.

In addition, we are exposed to foreign currency exchange rate risk through our Japanese Yen Term Loan Agreement ("Yen Term Loan") that EPO entered into in November 2008. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Japanese yen. We hedged this risk by entering into a foreign exchange purchase contract to fix the exchange rate. This purchase contract was designated as a cash flow hedge. At December 31, 2008, the fair value of this contract was $9.3 million. This contract will be settled in March 2009 upon repayment of the Yen Term Loan.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at 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. These assumptions include estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

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

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

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

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs. At December 31, 2008 our Level 3 financial assets consisted of ethane based contracts with a range of two to twelve months in term. This classification is primarily due to our reliance on broker quotes for this product due to the forward ethane markets being less than highly active.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity financial instruments	$ 4,030	$ 149,180	$ 32,552	$ 185,762
Foreign currency hedging financial instruments	--	9,284	--	9,284
Interest rate financial instruments	--	46,719	--	46,719
Total	$ 4,030	$ 205,183	$ 32,552	$ 241,765
Financial liabilities:				
Commodity financial instruments	$ 7,137	$ 274,238	$ --	$ 281,375
Foreign currency hedging financial instruments	--	109	--	109
Interest rate financial instruments	--	9,799	--	9,799
Total	$ 7,137	$ 284,146	$ --	$ 291,283

Fair values associated with our interest rate, commodity and foreign currency financial instrument portfolios were developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities during the year ended December 31, 2008:

Balance, January 1, 2008	$ (4,660)
Total gains (losses) included in:	
Net income	(34,807)
Other comprehensive loss	37,212
Purchases, issuances, settlements	34,807
Balance, December 31, 2008	$ 32,552

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses 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. The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques. The following table presents the estimated fair values of our financial instruments at December 31, 2008:

Financial Instruments	**Carrying Value**	**Fair Value**
Financial assets:		
Cash and cash equivalents, including restricted cash	$ 239,275	$ 239,275
Accounts receivable	1,243,117	1,243,117
Commodity financial instruments (1)	185,762	185,762
Foreign currency hedging financial instruments (2)	9,284	9,284
Interest rate hedging financial instruments (3)	46,719	46,719
Financial liabilities:		
Accounts payable and accrued expenses	1,683,150	1,683,150
Fixed-rate debt (principal amount) (4)	7,704,296	6,638,954
Variable-rate debt	1,341,750	1,341,750
Commodity financial instruments (1)	281,375	281,375
Foreign currency hedging financial instruments (2)	109	109
Interest rate hedging financial instruments (3)	9,799	9,799

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the Canadian dollar and Japanese yen.
(3) Represent interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(4) Due to the distress in the capital markets following the collapse of several major financial entities and uncertainty in the credit markets during 2008, corporate debt securities were trading at significant discounts.

Note 7. Inventories

Our inventory amounts were as follows at December 31, 2008:

Working inventory (1)	$ 200,439
Forward sales inventory (2)	162,376
Total inventory	$ 362,815

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of identified NGL and natural gas volumes dedicated to the fulfillment of forward sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

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), these volumes are valued at market-related prices during the month in which they are acquired. We capitalize as a component of inventory those ancillary costs (e.g. freight-in and other handling and processing charges) incurred in connection with volumes obtained through such contracts.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market adjustments when the carrying value of our inventories exceed their net realizable value.

Note 8. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at December 31, 2008:

	Estimated Useful Life in Years	
Plants and pipelines (1)	3-40 (5)	$ 12,296,318
Underground and other storage facilities (2)	5-35 (6)	900,664
Platforms and facilities (3)	20-31	634,761
Transportation equipment (4)	3-10	38,771
Land		54,627
Construction in progress		1,604,691
Total		15,529,832
Less accumulated depreciation		2,375,058
Property, plant and equipment, net		$ 13,154,774

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; 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, 18-40 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 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, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

We recorded $71.6 million in capitalized interest during the year ended December 31, 2008.

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 proved 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 by approximately $20.0 million annually 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.

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	$	40,614
Liabilities incurred		1,064
Liabilities settled		(7,229)
Revisions in estimated cash flows		1,163
Accretion expense		2,114
ARO liability balance, December 31, 2008	$	37,726

Property, plant and equipment at December 31, 2008 includes $9.9 million of asset retirement costs capitalized as an increase in the associated long-lived asset.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2008 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our Consolidated Balance Sheet.

Note 9. Investments in and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped 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 and advances to unconsolidated affiliates at December 31, 2008.

	Ownership Percentage		
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. (“VESCO”)	13.1%	$	37,673
K/D/S Promix, L.L.C. (“Promix”)	50%		46,380
Baton Rouge Fractionators LLC (“BRF”)	32.2%		24,160
Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”) (1)	49%		35,969
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company (“Jonah”)	19.4%		258,068
Evangeline (2)	49.5%		4,528
White River Hub, LLC (“White River Hub”) (3)	50%		21,387
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (“Poseidon”)	36%		60,233
Cameron Highway Oil Pipeline Company (“Cameron Highway”)	50%		250,833
Deepwater Gateway, L.L.C. (“Deepwater Gateway”)	50%		104,785
Neptune Pipeline Company, L.L.C. (“Neptune”)	25.7%		52,671
Nemo Gathering Company, LLC (“Nemo”)	33.9%		432
Texas Offshore Port System	33.3%		39,902
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (“BRPC”)	30%		12,633
La Porte (4)	50%		3,887
Total		$	953,541

(1) In December 2008, we acquired a 49% ownership interest in Skelly-Belvieu.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) In February 2008, we acquired a 50% ownership interest in White River Hub.
(4) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

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 and advances to unconsolidated affiliates. At December 31, 2008, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Jonah included excess cost amounts totaling $43.7 million, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities.

NGL Pipelines & Services

At December 31, 2008, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

VESCO. We own a 13.1% interest in VESCO, which owns a natural gas processing facility and related assets located in south Louisiana.

Promix. We own a 50% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

BRF. We own an approximate 32.2% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

Skelly-Belvieu. In December 2008, we acquired a 49% interest in Skelly-Belvieu for $36.0 million. Skelly-Belvieu owns a 570-mile pipeline that transports mixed NGLs to markets in southeast Texas.

The combined balance sheet information at December 31, 2008 of this segment's current unconsolidated affiliates is summarized below.

Current assets	$	64,080
Property, plant and equipment, net		368,059
Other assets		2,011
Total assets	$	434,150
Current liabilities	$	50,180
Other liabilities		24,271
Combined equity		359,699
Total liabilities and combined equity	$	434,150

Onshore Natural Gas Pipelines & Services

At December 31, 2008, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Evangeline. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline located in south Louisiana. A subsidiary of Acadian Gas, LLC owns the Evangeline interests, which were contributed to Duncan Energy Partners in February 2007 in connection with its initial public offering (see Note 15).

Jonah. Our equity interest in Jonah at December 31, 2008 is based on capital contributions we made to Jonah in connection with its Phase V expansion project. We completed Phase I of this expansion in July 2007 entitling us to approximately 19.4% in earnings and ownership with the remaining 80.6% entitlement to TEPPCO. See Note 15 for additional information regarding our Jonah affiliate. Jonah owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming.

White River Hub. We own a 50% interest in White River Hub, which owns a natural gas hub located in northwest Colorado. The hub was completed in December 2008.

The combined balance sheet information at December 31, 2008 of this segment's current unconsolidated affiliates is summarized below.

Current assets	$	97,470
Property, plant and equipment, net		1,082,251
Other assets		158,682
Total assets	$	1,338,403
Current liabilities	$	62,147
Other liabilities		21,890
Combined equity		1,254,366
Total liabilities and combined equity	$	1,338,403

Offshore Pipelines & Services

At December 31, 2008, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36% interest in Poseidon, which owns 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.

Cameron Highway. We own a 50% interest in Cameron Highway, which owns 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.

Deepwater Gateway. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo platform located in the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

Neptune. We own a 25.7% interest in Neptune, which owns Manta Ray Offshore Gathering System and Nautilus Pipeline System, which are natural gas pipelines located in the Gulf of Mexico.

Nemo. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

Texas Offshore Port System. In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels. We own a one-third interest in the Texas Offshore Port System. See Note 15 for additional information regarding this joint venture.

The combined balance sheet information at December 31, 2008 of this segment's current unconsolidated affiliates is summarized below.

Current assets	$	106,392
Property, plant and equipment, net		1,184,549
Other assets		3,608
Total assets	$	1,294,549
Current liabilities	$	58,379
Other liabilities		116,654
Combined equity		1,119,516
Total liabilities and combined equity	$	1,294,549

Petrochemical Services

At December 31, 2008, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

The combined balance sheet information at December 31, 2008 of this segment's current unconsolidated affiliates is summarized below.

Current assets	$	3,634
Property, plant and equipment, net		43,720
Total assets	$	47,354
Current liabilities	$	1,737
Other liabilities		2
Combined equity		45,615
Total liabilities and combined equity	$	47,354

Note 10. Business Combinations

Our expenditures for business combinations during the year ended December 31, 2008 were $202.2 million and primarily reflect the acquisitions described below.

Great Divide Gathering System Acquisition. In December 2008, one of our affiliates, 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 31-mile natural gas gathering system, the Great Divide Gathering System, located in the Piceance Basin of northwestern 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 1.4 Bcf/d Meeker natural gas treating and processing complex. A significant portion of these volumes are produced by EnCana, one of the largest natural gas producers in the region, and are dedicated the Great Divide and Piceance Creek Gathering Systems for the life of the associated lease holdings.

Tri-States and Belle Rose Acquisitions. In October 2008, we acquired additional 16.7% membership interests in both Tri-States and Belle Rose for total cash consideration of $19.9 million. As a result of this transaction, our ownership interest in Tri-States increased to 83.3%. We now own 100% of the membership interests in Belle Rose.

Tri-States owns a 194-mile NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. Belle Rose owns a 48-mile NGL pipeline located in Louisiana. These systems, in conjunction with the Wilprise pipeline, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana.

Acquisition of Remaining Interest in Dixie. In August 2008, we acquired the remaining 25.8% ownership interests in Dixie for cash consideration of $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,371-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstock) to customers along the U.S. Gulf Coast and southeastern United States.

Purchase Price Allocations. We accounted for business combinations completed during the year ended December 31, 2008 using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis.

	Great Divide	Tri-States	Belle Rose	Dixie	Other (1)	Total
Assets acquired in business combination:						
Current assets	$ --	$ 813	$ 143	$ 4,021	$ 35	$ 5,012
Property, plant and equipment, net	70,643	18,417	1,129	33,727	(12,773)	111,143
Intangible assets	9,760	--	--	--	12,747	22,507
Other assets	--	46	--	382	--	428
Total assets acquired	80,403	19,276	1,272	38,130	9	139,090
Liabilities assumed in business combination:						
Current liabilities	--	(581)	(68)	(2,581)	--	(3,230)
Long-term debt	--	--	--	(2,582)	--	(2,582)
Other long-term liabilities	(81)	--	(4)	(46,265)	--	(46,350)
Total liabilities assumed	(81)	(581)	(72)	(51,428)	--	(52,162)
Total assets acquired plus liabilities assumed	80,322	18,695	1,200	(13,298)	9	86,928
Total cash used for business combinations	125,175	18,695	1,200	57,089	1	202,160
Goodwill	$ 44,853	$ --	$ --	$ 70,387	$ (8)	$ 115,232

(1) Primarily represents non-cash reclassification adjustments to December 2007 preliminary fair value estimates for assets acquired in the South Monco natural gas pipeline business ("South Monco") acquisition.

As a result of our 100% ownership interest in Dixie, we used push-down accounting to record this business combination. In doing so, a temporary tax difference was created between the assets and liabilities of Dixie for financial reporting and tax purposes. Dixie recorded a deferred income tax liability of $45.1 million attributable to the temporary tax difference.

Note 11. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at December 31, 2008:

	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:			
Shell Processing Agreement	$ 206,216	$ (89,299)	$ 116,917
Encinal gas processing customer relationship	127,119	(28,045)	99,074
STMA and GulfTerra NGL Business customer relationships	49,784	(21,570)	28,214
Pioneer gas processing contracts	37,752	(3,601)	34,151
Markham NGL storage contracts	32,664	(18,509)	14,155
Toca-Western contracts	31,229	(10,280)	20,949
Other (1)	52,295	(14,745)	37,550
Segment total	537,059	(186,049)	351,010
Onshore Natural Gas Pipelines & Services:			
San Juan Gathering System customer relationships	331,311	(92,471)	238,840
Petal & Hattiesburg natural gas storage contracts	100,499	(36,524)	63,975
Other (2)	41,501	(10,854)	30,647
Segment total	473,311	(139,849)	333,462
Offshore Pipelines & Services:			
Offshore pipeline & platform customer relationships	205,845	(90,686)	115,159
Other	1,167	(107)	1,060
Segment total	207,012	(90,793)	116,219
Petrochemical Services:			
Mont Belvieu propylene fractionation contracts	53,000	(10,474)	42,526
Other	14,906	(2,707)	12,199
Segment total	67,906	(13,181)	54,725
Total all segments	$ 1,285,288	$ (429,872)	$ 855,416

(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 the December 31, 2007 South Monco acquisition.
(2) In 2008, we acquired $9.8 million of customer relationships due to the Great Divide business combination.

In general, our intangible assets fall within two categories – contract-based intangible assets and customer relationships. Contract-based intangible assets represent commercial rights we acquired in connection with business combinations or asset purchases. Customer relationship intangible assets represent customer bases that we acquired in connection with business combinations and asset purchases. The values assigned to 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.

We acquired $141.3 million of intangible assets primarily attributable to customer relationships we acquired in connection with the Encinal acquisition. The $132.9 million of intangible assets we acquired in connection with the Encinal acquisition represents the value we assigned to customer relationships, particularly the long-term relationship we now have with Lewis through natural gas processing and gathering arrangements. We recorded $127.1 million in our NGL Pipelines & Services segment associated with processing arrangements and $5.8 million in our Onshore Natural Gas Pipelines & Services segment associated with gathering arrangements. These intangible assets will be amortized to earnings over a 20-year life using methods that closely resemble the pattern in which we estimate the depletion of the underlying natural gas resources to occur.

We acquired numerous customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by GulfTerra and the

South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts to provide storage services for natural gas and NGLs that GulfTerra had entered into prior to the merger.

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 based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (iv) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets we acquired in connection with the GulfTerra Merger are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

The Shell Processing Agreement grants us the right to process Shell's (or its assignee's) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this intangible asset in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

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. The following table summarizes our goodwill amounts by segment at December 31, 2008:

NGL Pipelines & Services	
GulfTerra Merger	$ 23,854
Acquisition of Indian Springs natural gas processing business	13,162
Acquisition of Encinal	95,272
Acquisition of interest in Dixie	80,279
Acquisition of Great Divide	44,853
Other	11,518
Onshore Natural Gas Pipelines & Services	
GulfTerra Merger	279,956
Acquisition of Indian Springs natural gas gathering business	2,165
Offshore Pipelines & Services	
GulfTerra Merger	82,135
Petrochemical Services	
Acquisition of Mont Belvieu propylene fractionation business	73,690
Total	$ 706,884

In 2008, our only significant changes to goodwill were the recording of $70.4 million in connection with our acquisition of the remaining third party interest in Dixie and $44.9 million in connection 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 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. For additional information see Note 10.

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.

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.

The remainder of our goodwill amounts is associated with prior acquisitions, principally that of 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 December 31, 2008:

EPO senior debt obligations:	
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 800,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000
Petal GO Zone Bonds, variable rate, due August 2037	57,500
Yen Term Loan, 4.93% fixed-rate, due March 2009 (1)	217,596
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009 (1)	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000
Senior Notes L, 6.30% fixed-rate, due September 2017	800,000
Senior Notes M, 5.65% fixed-rate, due April 2013	400,000
Senior Notes N, 6.50% fixed-rate, due January 2019	700,000
Senior Notes O, 9.75% fixed-rate, due January 2014	500,000
Duncan Energy Partners' debt obligations:	
DEP I Revolving Credit Facility, variable rate, due February 2011	202,000
DEP II Term Loan Agreement, variable rate, due December 2011	282,250
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	--
Total principal amount of senior debt obligations	7,813,346
EPO Junior Subordinated Notes A, fixed/variable rate, due August 2066	550,000
EPO Junior Subordinated Notes B, fixed/variable rate, due January 2068	682,700
Total principal amount of senior and junior debt obligations	9,046,046
Other, non-principal amounts:	
Change in fair value of debt-related financial instruments (see Note 6)	51,935
Unamortized discounts, net of premiums	(7,306)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 6)	17,735
Total other, non-principal amounts	62,364
Total long-term debt	$ 9,108,410
Standby letters of credit outstanding	$ 1,000

(1) In accordance with SFAS 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at December 31, 2008. With respect to the Yen Term Loan and Senior Notes F due in October 2009, we have the ability to use available credit capacity under EPO's Multi-Year Revolving Credit Facility to fund the repayment of this debt.

(2) The Dixie Revolving Credit Facility was terminated in January 2009.

Letters of credit

At December 31, 2008, we had $1.0 million in standby letters outstanding under Duncan Energy Partners' DEP I Revolving Credit Facility.

Enterprise Products Partners-Subsidiary guarantor relationships

Enterprise Partners Products L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP I Revolving Credit Facility and the DEP II 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.

EPO's debt obligations

Multi-Year Revolving Credit Facility. In November 2007, EPO executed an amended and restated Multi-Year Revolving Credit Facility totaling $1.75 billion, which replaced an existing $1.25 billion multi-year revolving credit agreement. Amounts borrowed under the amended and restated credit agreement mature in November 2012, although EPO is permitted, 30 to 60 days before the maturity date in effect, to convert the principal balance of the revolving loans then outstanding into a non-revolving, one-year term loan (the "term-out option"). There is no sublimit on the amount of standby letters of credit that can be outstanding under the amended facility. EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. Enterprise Products Partners L.P. has guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

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 0.10% 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, upon the conversion of the revolving loans to term loans pursuant to the term-out option described above, the applicable margin will increase by 0.125% per annum and, if immediately prior to such conversion, 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 loans will increase by an additional 0.10% per annum.

EPO may increase the amount that may be borrowed under the facility, without the consent of the lenders, by an amount not exceeding $500.0 million by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. EPO may request unlimited one-year extensions of the maturity date by delivering a written request to the administrative agent, but any such extension shall be effective only if consented to by the required lenders in their sole discretion.

The Multi-Year Revolving Credit Facility contains various covenants related to EPO's ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires EPO to satisfy certain financial covenants at the end of each fiscal quarter. The credit agreement also restricts EPO's ability to pay cash distributions to us 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.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant in 2000, EPO entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility.

The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest, would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Petal GO Zone Bonds. In August 2007, Petal borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal Gas Storage, L.L.C. ("Petal") and the MBFC to pay a portion of the costs of certain natural gas storage facilities located in Petal, Mississippi. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by Petal. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt (“GO Zone”) bonds to various third parties. A portion of the GO Zone bond proceeds were being held by a third party trustee and reflected as a component of other assets on our balance sheet. During 2008, virtually all proceeds from the GO Zone bonds were released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of 30 years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act and the Gulf Opportunity Zone Act of 2005.

Petal MBFC Loan. In August 2007, Petal, a wholly owned subsidiary of EPO, 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. As of December 31, 2008, there was $8.9 million outstanding under the loan and the bonds. EPO will make advances on the bonds to the MBFC and the MBFC will in turn make identical advances to Petal under the promissory note. The promissory note and the taxable bonds have identical terms including fixed interest rates of 5.90% and maturities of fifteen years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act. Petal may prepay on the promissory note without penalty, and thus cause the bonds to be redeemed, any time after one year from their date of issue. The loan and bonds are netted in preparing our Consolidated Balance Sheet.

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’s obligations under the Yen Term Loan are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The Yen Term Loan will mature on March 30, 2009.

Under the Yen Term Loan, interest accrues on the loan at the Tokyo Interbank Offered Rate (“TIBOR”) plus 2%. EPO entered into foreign exchange currency swaps that effectively convert the TIBOR loan into a U.S. Dollar loan with a fixed interest rate (including the cost of the swaps) through maturity of approximately 4.93%. As a result, EPO received US$217.6 million net from this transaction. In addition, EPO executed a forward purchase exchange (yen principal and interest due) for March 30, 2009 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. For additional information see Note 6.

364-Day Revolving Credit Facility. In November 2008, EPO executed a 364-Day Revolving Credit Agreement (“364-Day Revolving Credit Facility”) in the amount of $375.0 million. EPO’s obligations under the 364-Day Revolving Credit Facility are not secured by any collateral; however, the obligations are guaranteed by Enterprise Products Partners L.P. pursuant to a guaranty agreement. The 364-Day Revolving Credit Facility will mature on November 16, 2009. As of December 31, 2008, there were no borrowings outstanding under this credit facility.

The 364-Day Revolving Credit Facility offers the following loans, each having different interest requirements: (i) London Interbank Offered Rate (“LIBOR”) loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin and (ii) Base Rate loans bear interest each day at a rate per annum equal to the higher of (a) the rate of interest announced by the administrative agent as its prime rate, (b) 0.5% per annum above the Federal Funds Rate in effect on such date , and (c) 1.0% per annum above LIBOR in effect on such date plus, in each case, the applicable Base Rate margin.

The commitments may be increased by an amount not to exceed $1.0 billion by adding one or more new lenders to the facility or increasing the commitments of existing lenders, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. With certain exceptions and after certain time periods, if EPO issues debt with a maturity of more than three years, the lenders’ commitments under the 364-Day Revolving Credit Facility will be reduced to the extent of any debt proceeds, and any outstanding loans in excess of such reduced commitments must be repaid.

Senior Notes B through L. These 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. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to EPGP. The 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.

Senior Notes M and N. In April 2008, EPO sold $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes M") and $700.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes N") under its universal registration statement. Senior Notes M were issued at 99.906% of their principal amount, have a fixed interest rate of 5.65% and mature in April 2013. Senior Notes N were issued at 99.866% of their principal amount, have a fixed interest rate of 6.50% and mature in January 2019.

Senior Notes M pay interest semi-annually in arrears on April 1 and October 1 of each year. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes M and N rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's borrowings under these notes are non-recourse to EPGP. Senior Notes M and N 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.

Senior Notes O. In December 2008, EPO sold $500.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes O") under its universal registration statement. Senior Notes O were issued at 100% of their principal amount, have a fixed interest rate of 9.75% and mature in January 2014.

Senior Notes O pay interest semi-annually in arrears on January 31 and July 31 of each year, commencing January 31, 2009. Net proceeds from the issuance of Senior Notes O were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes O rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's borrowings under these notes are non-recourse to EPGP. Senior Notes O 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.

Junior Notes A. In the third quarter of 2006, EPO sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 ("Junior Notes A"). EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). Enterprise Products Partners L.P. guaranteed EPO's repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows EPO to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the indenture agreement has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, neither we nor EPO cannot declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinated to the Junior Notes A.

The Junior Notes A bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, which commenced in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by EPO prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, EPO entered into a Replacement Capital Covenant in favor of the 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.

Junior Notes B. EPO sold $700.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 ("Junior Notes B") during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). Enterprise Products Partners L.P. has guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B 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 we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with Junior Notes A.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, which commenced in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month LIBOR for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that neither we nor EPO would redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

During the fourth quarter of 2008, we retired $17.3 million of our Junior Notes B for $10.2 million.

Duncan Energy Partners' debt obligations

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

DEP I Revolving Credit Facility. In February 2007, Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund a $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At December 31, 2008, the principal balance outstanding under this facility was $202.0 million.

This credit facility matures in February 2011 and 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 (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy 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 increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

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 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 II Term Loan Agreement. 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 the DEP II Midstream Businesses. See "Relationship with Duncan Energy Partners" in Note 15 for additional information regarding the DEP II Midstream Businesses.

Loans under the term loan agreement are due and payable on December 8, 2011. Duncan Energy Partners may also 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 ("ABR") loans or Eurodollar loans. The term loan agreement contains 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. As of December 31, 2008, there were no debt obligations outstanding under the Dixie Revolver. This credit facility was terminated in January 2009. EPO consolidated the debt of Dixie; however, EPO did not have the obligation to make interest or debt payments with respect to Dixie's debt.

Variable interest rates charged under this facility generally bore interest, at Dixie's election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the prime rate or (b) the Federal Funds Effective Rate plus 0.5%.

Canadian Debt Obligation

In May 2007, Canadian Enterprise Gas Products, Ltd. ("Canadian Enterprise"), 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.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate ("CPR") loans or Bankers' Acceptances and U.S. denominated borrowings may be comprised of ABR or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers' Acceptances carry interest at the rate for Canadian bankers' acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2008, there were no debt obligations outstanding under this credit facility.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2008.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2008.

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO's Multi-Year Revolving Credit Facility	0.97% to 6.00%	3.54%
DEP I Revolving Credit Facility	1.30% to 6.20%	4.25%
DEP II Term Loan Agreement	2.93% to 2.93%	2.93%
Dixie Revolving Credit Facility	0.81% to 5.50%	3.20%
Petal GO Zone Bonds	0.78% to 7.90%	2.24%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2009	$ --
2010	554,000
2011	934,250
2012	1,517,596
2013	750,000
Thereafter	5,290,200
Total scheduled principal payments	$ 9,046,046

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2008, (ii) total debt of each unconsolidated affiliate at December 31, 2008 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2009	2010	2011	2012	2013	After 2013
Poseidon	36%	$ 109,000	$ --	$ --	$ 109,000	$ --	$ --	$ --
Evangeline	49.5%	15,650	5,000	3,150	7,500	--	--	--
Total		$ 124,650	$ 5,000	$ 3,150	$ 116,500	$ --	$ --	$ --

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at December 31, 2008. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2008:

Poseidon. Poseidon has $109.0 million outstanding under its $150.0 million revolving credit facility that matures in May 2011. Interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon's total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. The variable interest rates charged on this debt at December 31, 2008 were 4.31%.

Evangeline. At December 31, 2008, short and long-term debt for Evangeline consisted of (i) $8.2 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. 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. Scheduled principal repayments on the Series B notes are $5.0 million in 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the 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 a Eurodollar rate plus 0.5%. The variable interest rates charged on this note at December 31, 2008 were 3.20%. Accrued interest payable related to the subordinated note was $9.8 million at December 31, 2008.

Note 13. Equity

At December 31, 2008, equity consisted of the capital account of Enterprise GP Holdings, accumulated other comprehensive loss and noncontrolling interest. Enterprise GP Holdings is a publicly traded limited partnership that completed an initial public offering of its common units in August 2005 and trades on the NYSE under the ticker symbol "EPE."

Accumulated Other Comprehensive Loss

The following table presents the components of accumulated other comprehensive loss at December 31, 2008:

Commodity financial instruments (1)	$	(114,077)
Interest rate financial instruments (1)		3,818
Foreign currency cash flow hedges (1)		10,594
Foreign currency translation adjustment (2)		(1,301)
Pension and postretirement benefit plans (3)		(751)
Subtotal		(101,717)
Amount attributable to noncontrolling interest		99,712
Total accumulated other comprehensive loss in member's equity	$	(2,005)

(1) See Note 6 for additional information regarding these components of accumulated other comprehensive loss.

(2) Relates to transactions of our Canadian NGL marketing subsidiary.

(3) See Note 5 for additional information regarding pension and postretirement benefit plans.

Noncontrolling Interest

The following table shows the components of noncontrolling interest at December 31, 2008:

Limited partners of Enterprise Products Partners:		
Third-party owners of Enterprise Products Partners (1)	$	5,010,596
Related party owners of Enterprise Products Partners (2)		649,390
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (3)		281,071
Joint venture partners (4)		112,578
Accumulated other comprehensive loss attributable to noncontrolling interest		(99,712)
Total noncontrolling interest on Consolidated Balance Sheet	$	5,953,923

(1) Consists of non-affiliate public unitholders of Enterprise Products Partners.

(2) Consists of unitholders of Enterprise Products Partners that are related party affiliates. This group is primarily comprised of EPCO and certain of its private company consolidated subsidiaries.

(3) Consists of non-affiliate public unitholders of Duncan Energy Partners.

(4) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole, Tri-States Pipeline, L.L.C. ("Tri-States"), Independence Hub, LLC and Wilprise Pipeline Company, L.L.C. ("Wilprise").

Note 14. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. 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 majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction in progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets 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.

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	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Segment assets:						
At December 31, 2008	$ 5,424,134	$ 4,033,312	$ 1,394,480	$ 698,157	$ 1,604,691	$ 13,154,774
Investments in and advances to unconsolidated affiliates (see Note 9):						
At December 31, 2008	144,182	283,983	508,856	16,520	--	953,541
Intangible assets, net (see Note 11):						
At December 31, 2008	351,010	333,462	116,219	54,725	--	855,416
Goodwill (see Note 11):						
At December 31, 2008	268,938	282,121	82,135	73,690	--	706,884

Note 15. Related Party Transactions

The following table summarizes our related party transactions as of December 31, 2008:

Accounts receivable - related parties:		
EPCO and affiliates	$	22,601
Energy Transfer Equity and affiliates		35,001
Total	$	57,602
Accounts payable - related parties:		
EPCO and affiliates	$	39,453
Energy Transfer Equity and affiliates		150
Total	$	39,603
Investments in and advances to unconsolidated affiliates: (1)		
Unconsolidated affiliates	$	15,332

(1) Net accounts receivable (payable) with unconsolidated affiliates are reclassified to "Investments in and advances to unconsolidated affiliates" on our Consolidated Balance Sheet.

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 private company subsidiaries;
- § Enterprise GP Holdings, which owns and controls EPGP;
- § TEPPCO, which is owned and controlled by Enterprise GP Holdings; and
- § the Employee Partnerships (see Note 4).

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 15.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP. At December 31, 2008, EPCO and its affiliates beneficially owned 152,506,527 (or 34.5%) of Enterprise Products Partners' outstanding common units, which includes 13,670,925 of Enterprise Products Partners' common units owned by Enterprise GP Holdings. In addition, at December 31, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as Enterprise Products Partners' managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

In connection with its general partner interest in Enterprise Products Partners, EPGP received cash distributions of $144.1 million from Enterprise Products Partners during the year ended December 31,

2008. This amount includes incentive distributions of $125.9 million for the year ended December 31, 2008.

Enterprise Products Partners and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from Enterprise Products Partners, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $405.2 million in cash distributions from Enterprise Products Partners and Enterprise GP Holdings during the year ended December 31, 2008.

The ownership interests in Enterprise Products Partners that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in Enterprise Products Partners that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO 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 lease office space in various buildings from affiliates of EPCO.

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. Enterprise Products Partners, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our 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 us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the “retained leases”). EPCO remains liable for the actual cash lease payments associated with these agreements. 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. 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.

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

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), 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 Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts with respect to 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, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings 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

  § 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.

Enterprise GP Holdings 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 chief executive officer 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 chief executive officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, 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 Enterprise GP Holdings, as described above but utilizing EPGP's chief executive officer 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.

In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

§ If any business opportunity not covered by the preceding bullet point (i.e. not involving equity securities) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), 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 chief executive officer 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 chief executive officer 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, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings 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. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including TEPPCO GP) or their controlled affiliates. Likewise, TEPPCO (including TEPPCO GP) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us and Enterprise GP Holdings 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.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of Enterprise Products Partners' common units, Enterprise GP Holdings' units, or both. See Note 4 for additional information regarding the Employee Partnerships.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns EPGP.

Jonah Joint Venture with TEPPCO. In August 2006, we became a joint venture partner with TEPPCO in Jonah, which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO shared equally in the costs of the Phase V expansion, which increased the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.4 Bcf/d and significantly reduced system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which has increased the system gathering capacity to 2.0 Bcf/d, was completed in July 2007 and the final phase of this expansion was completed in June 2008. We managed the Phase V construction project. Currently, the gathering capacity of this system is 2.4 Bcf/d.

Since August 1, 2006, we and TEPPCO have equally shared in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $306.5 million, which represents 50% of total Phase V costs incurred through December 31, 2008. We had a receivable of $1.0 million from TEPPCO at December 31, 2008 for Phase V expansion costs.

During the first quarter of 2008, Jonah initiated a separate project to increase gathering capacity on that portion of its system that serves the Pinedale production field. This new project is expected to increase overall capacity of the Jonah Gas Gathering System by an additional 0.2 Bcf/d. The total anticipated cost of this new project is $125.0 million, of which we will be responsible for our share of the construction costs.

TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. Since the first phase of this expansion was reached in July 2007, we and TEPPCO have shared earnings based on a formula that takes into account our respective capital contributions, including expenditures by TEPPCO prior to the expansion.

At December 31, 2008, we owned an approximate 19.4% interest in Jonah and TEPPCO owns 80.6%. We operate the Jonah system. We account for our investment in the Jonah joint venture using the equity method.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Texas Offshore Port System Joint Venture. In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of the Texas Offshore Port System, a joint venture to design, construct, operate and own a Texas offshore crude oil port and a related onshore pipeline and storage system that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a storage facility near Texas City, Texas. The joint venture's complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. The timing of the construction and related capital costs of the TOPS and PACE projects will be affected by the expansion plans of Motiva and the acquisition of requisite permits.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures currently expected to occur in 2010 and 2011. We and TEPPCO have each guaranteed up to approximately $700.0 million, which includes a contingency amount for potential cost overruns, of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of December 31, 2008, our investment in the Texas Offshore Port System was $39.9 million.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of Energy Transfer Partners, L.P. ("ETP"). Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

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 of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of 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 the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At December 31, 2008, 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 OLP, a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business.

At December 31, 2008, EPO owned approximately 74.1% of Duncan Energy Partners' limited partner interests and 100% of its general partner.

DEP I Midstream Businesses

On February 5, 2007, EPO contributed a 66% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown of assets (the "DEP I dropdown"). EPO retained the remaining 34% equity interest in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene'), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL").

As consideration for controlling equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed to EPO (i) $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, (ii) $198.9 million in borrowings under its DEP I Revolving Credit Facility and (iii) a net 5,351,571 common units of Duncan Energy Partners. See Note 12 for information regarding the debt obligations of Duncan Energy Partners.

DEP II Midstream Businesses

On December 8, 2008, Duncan Energy Partners entered into the DEP II Purchase Agreement with EPO and Enterprise GTM, a wholly owned subsidiary of EPO. Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100% of the membership interests in Enterprise III from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% membership interest in Enterprise Texas. Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." EPO was the sponsor of this second dropdown transaction (the "DEP II dropdown"). Enterprise GTM retained the remaining limited partner and member interests in the DEP II Midstream Businesses.

As consideration for controlling equity interests in the DEP II Midstream Businesses, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having a market value of $449.5 million from Duncan Energy Partners. The Class B limited partner units automatically converted to common units of Duncan Energy Partners on February 1, 2009. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under the DEP II Term Loan Agreement. See Note 12 for information regarding the debt obligations of Duncan Energy Partners.

Generally, the DEP II dropdown transaction documents provide that to the extent that the DEP II Midstream Businesses generate cash sufficient to pay distributions to their partners or members, such cash will be distributed to Enterprise III (a wholly owned by Duncan Energy Partners) and Enterprise GTM (our wholly owned subsidiary) in an amount sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of this amount will be distributed 98% to Enterprise GTM and 2% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%.

Duncan Energy Partners paid a pro rated cash distribution of $0.1115 per unit on the Class B units with respect to the fourth quarter of 2008.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

Omnibus Agreement

On December 8, 2008, we entered into an amended and restated Omnibus Agreement with Duncan Energy Partners. The key provisions of this agreement are summarized as follows:

§ indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses we contributed to Duncan Energy Partners in connection with the respective dropdown transactions;

- § funding by EPO of 100% of post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of Duncan Energy Partners' initial public offering;

- § funding by EPO of 100% of post-December 8, 2008 capital expenditures (estimated at $1.4 million) to complete the Sherman Extension natural gas pipeline;

- § a right of first refusal to EPO in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and

- § a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and Duncan Energy Partners have also agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed.

EPGP's ACG Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect Enterprise Products Partners' unitholders.

EPO has indemnified Duncan Energy Partners against certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in connection with the DEP I and DEP II dropdown transactions. These liabilities include both known and unknown environmental and related liabilities. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage, and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

- § certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and

- § certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of its common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the ASA, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the ASA with EPO, EPCO and other affiliates of EPCO.

Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $32.5 million in connection with the Omnibus Agreement during the year ended December 31, 2008. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement

The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66% share of these projects from EPO within 90 days of such projects being placed in service.

EPO made cash contributions of $99.5 million under the Caverns LLC Agreement during the year ended December 31, 2008 to fund 100% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66% for Duncan Energy Partners and 34% for EPO. EPO expects to make additional contributions of approximately $27.5 million to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100% of the depreciation related to projects that it has fully funded.

The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

Company and Limited Partnership Agreements – DEP II Midstream Businesses

On December 8, 2007, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II dropdown transaction. Collectively, these amended and restated agreements provide for the following:

§ the acquisition by Enterprise III (a wholly owned subsidiary of Duncan Energy Partners) from Enterprise GTM (our wholly owned subsidiary) of a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% member interest in Enterprise Texas;

§ the payment of distributions in accordance with an overall "waterfall" approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2% to Enterprise III. The initial annual fixed return amount of 11.85% will be increased by 2% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%;

§ the funding of operating cash flow deficits in accordance with each owner's respective partner or member interest; and

- the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

  Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner's Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 9 for a discussion of this alignment of commercial interests. 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. In addition, Duncan Energy Partners furnished $1.0 million in letters of credit on behalf of Evangeline at December 31, 2008.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements.

- We pay Jonah for natural gas purchases from its gathering system.

- We perform management services for certain of our unconsolidated affiliates.

Note 16. Income Taxes

Our 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 Franchise Tax in 2006, we have become a taxable entity in the state of Texas.

Significant components of deferred tax assets and deferred tax liabilities as of December 31, 2008 are as follows:

Deferred tax assets:	
Net operating loss carryovers	$ 26,311
Property, plant and equipment	753
Credit carryover	26
Charitable contribution carryover	20
Employee benefit plans	2,631
Deferred revenue	964
Reserve for legal fees and damages	289
Equity investment in partnerships	596
AROs	76
Accruals	898
Total deferred tax assets	32,564
Valuation allowance	(3,932)
Net deferred tax assets	28,632
Deferred tax liabilities:	
Property, plant and equipment	92,899
Other	43
Total deferred tax liabilities	92,942
Total net deferred tax liabilities	$ (64,310)
Current portion of total net deferred tax assets	$ 1,395
Long-term portion of total net deferred tax liabilities	$ (65,705)

We had net operating loss carryovers of $26.3 million at December 31, 2008. These losses expire in various years between 2009 and 2028 and are subject to limitations on their utilization. We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. The valuation allowance was $3.9 million at December 31, 2008 and serves to reduce the recognized tax benefit associated with carryovers of our corporate entities to an amount that will, more likely than not, be realized.

We have deferred tax liabilities on property plant and equipment of $92.9 million at December 31, 2008. The 2008 balance is comprised primarily of $45.1 million related to the difference in book and tax basis of property, plant and equipment resulting from the acquisition of the remaining equity interest of Dixie Pipeline. See Note 10 for additional information.

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, 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 Revised Texas Franchise 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 Revised Texas Franchise Tax, we recorded a net deferred tax liability of $0.9 million during the year ended December 31, 2008.

Note 17. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business 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 as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and Enterprise Products Partners or its affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, its current and certain 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 certain 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; (ii) the sale by TEPPCO of its Pioneer natural gas processing plant to Enterprise Products Partners in March 2006; and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's IDRs in exchange for TEPPCO common 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) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 15 for additional information regarding our relationship with TEPPCO.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the U.S. Department of Justice ("DOJ") 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. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether ("MTBE"). In general, such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us 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 stormwater permit and appropriate stormwater plan. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. The State has not yet assessed penalties and we are unable to predict the amount of penalties that may be assessed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position.

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 as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 40% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws, and Marathon believes there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. The State seeks penalties above $100,000. Marathon continues to work with the State to determine if resolution of the case is possible.

Contractual Obligations

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

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Scheduled maturities of long-term debt	$ 9,046,046	$ --	$ 554,000	$ 934,250	$ 1,517,596	$ 750,000	$ 5,290,200
Estimated cash payments for interest	$ 9,351,928	$ 544,658	$ 522,633	$ 471,253	$ 451,450	$ 369,673	$ 6,992,261
Operating lease obligations	$ 331,419	$ 32,299	$ 27,541	$ 27,831	$ 27,066	$ 24,481	$ 192,201
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 5,225,141	$ 323,309	$ 515,102	$ 635,000	$ 660,626	$ 487,984	$ 2,603,120
NGLs	$ 1,923,792	$ 969,870	$ 136,422	$ 136,250	$ 136,250	$ 136,250	$ 408,750
Petrochemicals	$ 1,746,138	$ 685,643	$ 376,636	$ 247,757	$ 181,650	$ 86,768	$ 167,684
Other	$ 37,455	$ 19,202	$ 3,459	$ 3,322	$ 3,051	$ 2,919	$ 5,502
Underlying major volume commitments:							
Natural gas (in BBtus)	981,955	56,650	93,150	115,925	120,780	93,950	501,500
NGLs (in MBbls)	56,622	23,576	4,726	4,720	4,720	4,720	14,160
Petrochemicals (in MBbls)	67,696	24,949	13,420	10,428	7,906	3,759	7,234
Service payment commitments	$ 529,402	$ 52,614	$ 50,902	$ 49,501	$ 47,025	$ 46,142	$ 283,218
Capital expenditure commitments	$ 521,262	$ 521,262	$ --	$ --	$ --	$ --	$ --

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements such as the indentures governing EPO's senior notes and the credit agreement governing EPO's Multi-Year Revolving Credit Facility. 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 an affiliate of EPCO, (iii) a railcar unloading terminal in

Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from two to 28 years and include renewal options that could extend the agreements for up to an additional 20 years.

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 year ended December 31, 2008.

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 at our formation. EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2008, 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 2009 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 partners' 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 have 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.

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 NGLs, certain petrochemicals and natural gas 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, 2008 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2008, 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 such as equipment maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our 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 15). This includes costs associated with unit option awards granted to these employees to purchase Enterprise Products Partners' common units. At December 31, 2008, there were 2,168,500 and 795,000 unit options outstanding under the EPCO 1998 Plan and EPD 2008 LTIP, respectively, for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of unit option awards outstanding at December 31, 2008 was $26.32 and $30.93 per common unit under the EPCO 1998 Plan and EPD 2008 LTIP, respectively. At December 31, 2008, 548,500 of these unit options were exercisable under the EPCO 1998 Plan. An additional 365,000, 480,000 and 775,000 of these unit options will be exercisable in 2009, 2010 and 2012, respectively under the EPCO 1998 Plan. The 795,000 unit options outstanding under the EPD 2008 LTIP will become exercisable in 2013. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 4 for additional information regarding our accounting for equity awards.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2008, claims against us totaled approximately $15.4 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, if any, that might result from the resolution of such disputes have not been reflected in our Consolidated Balance Sheet.

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 (i) accrued as product payables on our Consolidated Balance Sheet, (ii) in transit for delivery to our customers or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our natural gas, NGL and petrochemical storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2008, NGL and petrochemical products aggregating 29.6 million barrels were due to be redelivered to their owners along with 18.5 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Note 18. 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, certain petrochemicals and crude oil. As such, our financial condition, 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. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations 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 transported, gathered or processed 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 and crude oil handled by our facilities.

A reduction in demand for NGL 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 NGLs, (iii) increased competition from petroleum-based 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.

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.

Our revenues are derived from a wide customer base. During 2008 our largest customer was LBI and its affiliates. On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $17.3 million of credit exposure to LBI, which was reduced to approximately $10.0 million through remedies provided under certain pipeline tariffs. In addition, we are seeking to have LBI accept certain contracts and have filed claims pursuant to current Bankruptcy Court Orders that we expect will allow us to recover the majority of the remaining credit exposure.

Counterparty Risk with Respect to Financial Instruments

In those situations where we are exposed to credit risk in our financial 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.

Weather-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. 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 Enterprise Products Partners' common units.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us.

Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available.

Hurricane Ivan insurance claims. During the year ended December 31, 2008, we did not receive any reimbursements from insurance carriers related to property damage claims associated with this storm. We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. During the year ended December 31, 2008, we did not receive any proceeds from these claims. We are continuing our efforts to collect residual balances from this storm.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. With respect to these storms, we have $30.5 million of estimated property damage claims outstanding at December 31, 2008, that we believe are probable of collection during the period 2009. We continue to pursue collection of our property damage claims related to these named storms. As of December 31, 2008, we had received all proceeds from our business interruption claims related to these storm events.

Hurricanes Gustav and Ike insurance claims. In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. We expect to file property damage insurance claims to the extent repair costs exceed deductible amounts. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

Proceeds from Business Interruption and Property Damage Claims

The following table summarizes proceeds we received during the year ended December 31, 2008 from business interruption and property damage insurance claims with respect to certain named storms:

Business interruption proceeds:	
Hurricane Katrina	$ 501
Hurricane Rita	662
Total proceeds	1,163
Property damage proceeds:	
Hurricane Katrina	9,404
Hurricane Rita	2,678
Total proceeds	12,082
Total	$ 13,245

At December 31, 2008, we have $39.0 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2009. In February 2009, we collected $20.8 million of the amounts outstanding. 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.

During 2008, we collected $0.2 million of business interruption proceeds that were not related to storm events.