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

# FORM 10-Q

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

For the quarterly period ended September 30, 2010

**OR**

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

For the transition period from ___ to ___.

Commission file number: 1-14323

# ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

| | |
|---|---|
| **Delaware** | **76-0568219** |
| (State or Other Jurisdiction of Incorporation or Organization) | (I.R.S. Employer Identification No.) |

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

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

| | | |
|---|---|---|
| Large accelerated filer ☑ | & #160; | Accelerated filer o |
| Non-accelerated filer o (Do not check if a smaller reporting company) | | Small er reporting company o |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ☑

There were 637,950,843 common units, including 3,608,258 restricted common units, and 4,520,431 Class B units (which generally vote together with the common units) of Enterprise Products Partners L.P. outstanding at November 1, 2010. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

**ENTERPRISE PRODUCTS PARTNERS L.P.**
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## PART I. FINANCIAL INFORMATION.

**Item 1. *Financial Statements*.**

### ENTERPRISE PRODUCTS PARTNERS L.P.
### UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
### (Dollars in millions)

| ASSETS | September 30, 2010 | December 31, 2009 |
|---|---|---|
| **Current assets:** | | |
| Cash and cash equivalents | $ 42.7 | $ 54.7 |
| Restricted cash | 32.5 | 63.6 |
| Accounts and notes receivable – trade, net of allowance for doubtful accounts of $18.1 at September 30, 2010 and $16.8 at December 31, 2009 | 3,036.6 | 3,099.0 |
| Accounts receivable – related parties | 31.0 | 38.4 |
| Inventories | 1,210.0 | 711.9 |
| Prepaid and other current assets | 290.6 | 279.3 |
| Total current assets | 4,643.4 | 4,246.9 |
| **Property, plant and equipment, net** | 18,810.0 | 17,689.2 |
| **Investments in unconsolidated affiliates** | 864.7 | 890.6 |
| **Intangible assets, net of accumulated amortization of $894.7 at September 30, 2010 and $795.0 at December 31, 2009** | 1,860.3 | 1,064.8 |
| **Goodwill** | 2,052.7 | 2,018.3 |
| **Other assets** | 241.6 | 241.8 |
| Total assets | $ 28,472.7 | $ 26,151.6 |
| **LIABILITIES AND EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable – trade | $ 511.2 | $ 410.6 |
| Accounts payable – related parties | 98.2 | 69.8 |
| Accrued product payables | 3,338.6 | 3,393.0 |
| Accrued interest | 172.2 | 228.0 |
| Other current liabilities | 470.5 | 434.6 |
| Total current liabilities | 4,590.7 | 4,536.0 |
| **Long-term debt** (see Note 10) | 12,704.8 | 11,346.4 |
| **Deferred tax liabilities** | 75.0 | 71.7 |
| **Other long-term liabilities** | 266.6 | 155.2 |
| **Commitments and contingencies** | | |
| **Equity:** (see Note 11) | | |
| Enterprise Products Partners L.P. partners' equity: | | |
| Limited Partners: | | |
| Common units (635,621,204 units outstanding at September 30, 2010 and 603,202,828 units outstanding at December 31, 2009) | 10,106.2 | 9,173.5 |
| Restricted common units (3,631,121 units outstanding at September 30, 2010 and 2,720,882 units outstanding at December 31, 2009) | 59.3 | 37.7 |
| Class B units (4,520,431 units outstanding at September 30, 2010 and December 31, 2009) | 118.5 | 118.5 |
| General partner | 209.5 | 190.8 |
| Accumulated other comprehensive loss | (185.4) | (8.4) |
| Total Enterprise Products Partners L.P. partners' equity | 10,308.1 | 9,512.1 |
| Noncontrolling interest | 527.5 | 530.2 |
| Total equity | 10,835.6 | 10,042.3 |
| Total liabilities and equity | $ 28,472.7 | $ 26,151.6 |

See Notes to Unaudited Condensed Consolidated Financial Statements.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS**
**(Dollars in millions, except per unit amounts)**

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Revenues:** | | | | |
| Third parties | $ 7,934.1 | $ 6,679.0 | $ 23,673.6 | $ 16,688.4 |
| Related parties | 133.7 | 110.4 | 482.1 | 422.2 |
| Total revenues (see Note 12) | 8,067.8 | 6,789.4 | 24,155.7 | 17,110.6 |
| **Costs and expenses:** | | | | |
| Operating costs and expenses: | | | | |
| Third parties | 7,117.1 | 6,128.2 | 21,441.1 | 15,046.4 |
| Related parties | 343.0 | 267.6 | 965.1 | 750.5 |
| Total operating costs and expenses | 7,460.1 | 6,395.8 | 22,406.2 | 15,796.9 |
| General and administrative costs: | | | | |
| Third parties | 17.2 | 26.9 | 45.9 | 56.3 |
| Related parties | 38.8 | 25.4 | 85.6 | 77.0 |
| Total general and administrative costs | 56.0 | 52.3 | 131.5 | 133.3 |
| Total costs and expenses (see Note 12) | 7,516.1 | 6,448.1 | 22,537.7 | 15,930.2 |
| **Equity in income of unconsolidated affiliates** | 17.5 | 15.0 | 50.2 | 32.0 |
| **Operating income** | 569.2 | 356.3 | 1,668.2 | 1,212.4 |
| **Other income (expense):** | | | | |
| Interest expense | (179.7) | (161.0) | (496.9) | (472.0) |
| Interest income | 0.9 | 0.3 | 1.6 | 1.9 |
| Other, net | 0.4 | (0.1) | 0.2 | 0.3 |
| Total other expense, net | (178.4) | (160.8) | (495.1) | (469.8) |
| **Income before provision for income taxes** | 390.8 | 195.5 | 1,173.1 | 742.6 |
| Provision for income taxes | (4.9) | (7.7) | (20.1) | (26.8) |
| **Net income** | 385.9 | 187.8 | 1,153.0 | 715.8 |
| Net (income) loss attributable to noncontrolling interests | (14.0) | 25.1 | (46.1) | (91.0) |
| **Net income attributable to Enterprise Products Partners L.P.** | $ 371.9 | $ 212.9 | $ 1,106.9 | $ 624.8 |
| | | | | |
| **Allocation of net income attributable to Enterprise Products Partners L.P.:** | | | | |
| Limited partners | $ 307.0 | $ 171.3 | $ 918.7 | $ 504.6 |
| General partner | $ 64.9 | $ 41.6 | $ 188.2 | $ 120.2 |
| | | | | |
| **Basic earnings per unit** (see Note 14) | $ 0.48 | $ 0.36 | $ 1.45 | $ 1.09 |
| **Diluted earnings per unit** (see Note 14) | $ 0.47 | $ 0.36 | $ 1.44 | $ 1.09 |

See Notes to Unaudited Condensed Consolidated Financial Statements.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED**
**COMPREHENSIVE INCOME**
**(Dollars in millions)**

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Net income** | $ 385.9 | $ 187.8 | $ 1,153.0 | $ 715.8 |
| **Other comprehensive income (loss):** | | | | |
| Cash flow hedges: | | | | |
| Commodity derivative instrument losses during period | (64.1) | (8.3) | (31.0) | (146.9) |
| Reclassification adjustment for (gains) losses included in net income related to commodity derivative instruments | (25.6) | 77.8 | (10.6) | 176.3 |
| Interest rate derivative instrument gains (losses) during period | (65.5) | (8.0) | (142.0) | 7.1 |
| Reclassification adjustment for losses included in net income related to interest rate derivative instruments | 3.2 | 2.8 | 9.8 | 7.6 |
| Foreign currency derivative gains (losses) during period | 0.1 | 0.2 | (0.1) | (10.3) |
| Reclassification adjustment for gains included in net income related to foreign currency derivative instruments | -- | -- | (0.3) | -- |
| Total cash flow hedges | (151.9) | 64.5 | (174.2) | 33.8 |
| Foreign currency translation adjustment | 0.5 | 1.1 | 0.3 | 1.7 |
| Change in funded status of pension and postretirement plans, net of tax | -- | -- | (0.9) | -- |
| Total other comprehensive income (loss) | (151.4) | 65.6 | (174.8) | 35.5 |
| **Comprehensive income** | 234.5 | 253.4 | 978.2 | 751.3 |
| Comprehensive (income) loss attributable to noncontrolling interests | (14.8) | 23.3 | (48.3) | (96.4) |
| **Comprehensive income attributable to Enterprise Products Partners L.P.** | $ 219.7 | $ 276.7 | $ 929.9 | $ 654.9 |

See Notes to Unaudited Condensed Consolidated Financial Statements.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS**
**(Dollars in millions)**

| | For the Nine Months Ended September 30, 2010 | For the Nine Months Ended September 30, 2009 |
|---|---|---|
| **Operating activities:** | | |
| Net income | $ 1,153.0 | $ 715.8 |
| *Adjustments to reconcile net income to net cash flows provided by operating activities:* | | |
| Depreciation, amortization and accretion | 704.2 | 619.9 |
| Non-cash asset impairment charges | 1.5 | 26.3 |
| Equity in income of unconsolidated affiliates | (50.2) | (32.0) |
| Distributions received from unconsolidated affiliates | 82.3 | 55.2 |
| Operating lease expenses paid by EPCO | 0.5 | 0.5 |
| Gains from asset sales and related transactions | (45.4) | (0.5) |
| Loss on forfeiture of investment in Texas Offshore Port System | -- | 68.4 |
| Deferred income tax expense | 3.7 | 2.5 |
| Changes in fair market value of derivative instruments | (10.8) | 10.6 |
| Effect of pension settlement recognition | (0.2) | (0.1) |
| Net effect of changes in operating accounts (see Note 17) | (423.5) | (574.9) |
| Net cash flows provided by operating activities | 1,415.1 | 891.7 |
| **Investing activities:** | | |
| Capital expenditures | (1,405.1) | (1,100.4) |
| Contributions in aid of construction costs | 13.9 | 12.8 |
| Decrease in restricted cash | 37.9 | 100.8 |
| Cash used for business combinations (see Note 8) | (1,233.0) | (74.5) |
| Investments in unconsolidated affiliates | (6.3) | (13.9) |
| Proceeds from asset sales and related transactions | 89.6 | 2.9 |
| Other investing activities | 1.5 | 0.1 |
| Cash used in investing activities | (2,501.5) | (1,072.2) |
| **Financing activities:** | | |
| Borrowings under debt agreements | 4,103.8 | 4,963.8 |
| Repayments of debt | (2,753.8) | (4,594.0) |
| Debt issuance costs | (14.7) | (5.5) |
| Cash distributions paid to partners | (1,263.1) | (860.1) |
| Unit option-related reimbursements to EPCO | (9.7) | (0.5) |
| Cash distributions paid to noncontrolling interests | (54.0) | (322.3) |
| Cash contributions from noncontrolling interests | 2.8 | 138.7 |
| Net cash proceeds from issuance of common units | 1,058.0 | 877.7 |
| Cash proceeds from exercise of unit options | 6.6 | 0.5 |
| Acquisition of treasury units | (3.1) | (1.8) |
| Other financing activities | 1.3 | -- |
| Cash provided by financing activities | 1,074.1 | 196.5 |
| Effect of exchange rate changes on cash | 0.3 | (0.4) |
| **Net change in cash and cash equivalents** | (12.3) | 16.0 |
| **Cash and cash equivalents, January 1** | 54.7 | 61.7 |
| **Cash and cash equivalents, September 30** | $ 42.7 | $ 77.3 |

See Notes to Unaudited Condensed Consolidated Financial Statements.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY**
**(See Note 11 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Loss)**
**(Dollars in millions)**

| | Enterprise Products Partners L.P. | | | | |
|---|---|---|---|---|---|
| | Limited Partners | General Partner | Accumulated Other Comprehensive Loss | Noncontrolling Interest | Total |
| **Balance, December 31, 2009** | $ 9,329.7 | $ 190.8 | $ (8.4) | $ 530.2 | $ 10,042.3 |
| Net income | 918.7 | 188.2 | -- | 46.1 | 1,153.0 |
| Operating lease expenses paid by EPCO | 0.5 | -- | -- | -- | 0.5 |
| Cash distributions paid to partners | (1,071.8) | (191.3) | -- | -- | (1,263.1) |
| Unit option-related reimbursements to EPCO | (9.7) | -- | -- | -- | (9.7) |
| Cash distributions paid to noncontrolling interests | -- | -- | -- | (54.0) | (54.0) |
| Common units issued to EPCO in exchange for equity interests in trucking business | 30.6 | -- | -- | -- | 30.6 |
| Net cash proceeds from issuance of common units | 1,036.7 | 21.3 | -- | -- | 1,058.0 |
| Cash proceeds from exercise of unit options | 6.6 | -- | -- | -- | 6.6 |
| Cash contributions from noncontrolling interests | -- | -- | -- | 2.8 | 2.8 |
| Amortization of equity awards | 45.5 | 0.8 | -- | 0.2 | 46.5 |
| Acquisition of treasury units | (3.0) | (0.1) | -- | -- | (3.1) |
| Foreign currency translation adjustment | -- | -- | 0.3 | -- | 0.3 |
| Change in value of cash flow hedges | -- | -- | (176.4) | 2.2 | (174.2) |
| Other | 0.2 | (0.2) | (0.9) | -- | (0.9) |
| **Balance, September 30, 2010** | $ 10,284.0 | $ 209.5 | $ (185.4) | $ 527.5 | $ 10,835.6 |

| | Enterprise Products Partners L.P. | | | | |
|---|---|---|---|---|---|
| | Limited Partners | General Partner | Accumulated Other Comprehensive Loss | Noncontrolling Interest | Total |
| **Balance, December 31, 2008** | $ 6,063.1 | $ 123.6 | $ (97.2) | $ 3,206.4 | $ 9,295.9 |
| Net income | 504.6 | 120.2 | -- | 91.0 | 715.8 |
| Operating lease expenses paid by EPCO | 0.5 | -- | -- | -- | 0.5 |
| Cash distributions paid to partners | (735.2) | (124.9) | -- | -- | (860.1) |
| Unit option-related reimbursements to EPCO | (0.5) | -- | -- | -- | (0.5) |
| Cash distributions paid to noncontrolling interests | -- | -- | -- | (322.3) | (322.3) |
| Deconsolidation of Texas Offshore Port System (see Note 1) | -- | -- | -- | (33.4) | (33.4) |
| Net cash proceeds from issuance of common units | 860.2 | 17.5 | -- | -- | 877.7 |
| Cash proceeds from exercise of unit options | 0.5 | -- | -- | -- | 0.5 |
| Cash contributions from noncontrolling interests | -- | -- | -- | 138.7 | 138.7 |
| Amortization of equity awards | 13.5 | 0.2 | -- | 3.1 | 16.8 |
| Acquisition of treasury units | (1.8) | -- | -- | -- | (1.8) |
| Foreign currency translation adjustment | -- | -- | 1.7 | -- | 1.7 |
| Change in value of cash flow hedges | -- | -- | 28.4 | 5.4 | 33.8 |
| Other | -- | -- | -- | 0.3 | 0.3 |
| **Balance, September 30, 2009** | $ 6,704.9 | $ 136.6 | $ (67.1) | $ 3,089.2 | $ 9,863.6 |

See Notes to Unaudited Condensed Consolidated Financial Statements.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

*Except unit-related amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnotes are stated in millions of dollars.*

## SIGNIFICANT RELATIONSHIPS REFERENCED IN THESE NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, which is a wholly owned subsidiary of Enterprise Products Partners. Enterprise Products Partners conducts substantially all of its business through EPO and its consolidated subsidiaries. References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner. EPGP is responsible for managing the business and operations of Enterprise Products Partners.

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 "Holdings" mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Holdings owns EPGP. On September 3, 2010, we and Holdings entered into an Agreement and Plan of Merger (the "Holdings Merger Agreement") that would, if approved by Holdings' unitholders, result in the merger of Holdings with a wholly owned subsidiary of ours through a unit-for-unit exchange (the "Holdings Merger"). See Note 1 for additional information regarding the proposed Holdings Merger. The general partner of Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiary of Dan Duncan LLC.

The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the "DD LLC Voting Trust Agreement"), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the "DD LLC Trustees") are: (i) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also a director of EPE Holdings; (ii) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (iii) Richard H. Bachmann, who is currently an Executive Vice President, the Chief Legal Officer and Secretary of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann also serve as directors of EPE Holdings.

The DD LLC Voting Trust Agreement requires that there always be two "Independent Voting Trustees" serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within 90 days of the vacancy's occurrence, the CEO of our general partner, currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a "Duncan Voting Trustee." The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. For all purposes whatsoever, the DD LLC Trustees are required to treat the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan LLC. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take party in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and, subject to the provisions of the DD LLC Voting Trust Agreement, to rece ive distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, EPO, Duncan Energy Partners, DEP GP, EPGP, Holdings and EPE Holdings were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO, Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger."

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") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC.

References to the "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See Note 3 for additional information.

## Note 1. Partnership Operations and Basis of Presentation

### *General*

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. 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. Our assets include: 49,100 miles of onshore and offshore pipelines; approximately 200 million barrels ("MMBbls") of storage capacity for NG Ls, refined products and crude oil; and 27 billion cubic feet ("Bcf") of natural gas storage capacity.

Our midstream energy operations include: natural gas transportation, gathering, processing and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and storage; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 12 for additional information regarding our business segments.

We are owned 98% by our limited partners and 2% by our general partner, EPGP. We, EPGP, Holdings, EPE Holdings, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 13 for information regarding the ASA and related party matters.

### *Interim Reporting*

Our results of operations for the three and nine months ended September 30, 2010 are not necessarily indicative of results expected for the full year. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2009 (the "2009 Form 10-K").

***Proposed Merger of Holdings with Enterprise Products Partners***

On September 3, 2010, we and Holdings entered into an Agreement and Plan of Merger that would, if approved by Holdings' unitholders, result in the merger of Holdings with a wholly owned subsidiary of ours through a unit-for-unit exchange. Consequently, Holdings would become a wholly owned subsidiary of ours. Under the terms of the Holdings Merger Agreement, Holdings' unitholders will be entitled to receive 1.5 of our common units in exchange for each Holdings limited partner unit they own at closing. As a result, we expect to issue, in the aggregate, 208,813,477 of our common units to Holdings' unitholders. The proposed transaction would also result in the cancellation of 21,563,177 of our common units currently held by Holdings as well as our general partner's 2% eco nomic interest and its incentive distribution rights in us. Affiliates of EPCO will continue to own our general partner following the merger.

The proposed merger must receive the affirmative vote of Holdings' unitholders owning at least a majority of Holdings' outstanding units as of the record date. Subject to the terms and conditions of a support agreement, privately held affiliates of EPCO (the "Holdings supporting unitholders") have agreed to vote their 105,739,220 Holdings' units, representing approximately 76% of Holdings' outstanding units, in favor of the proposed merger. The support agreement will automatically terminate on December 31, 2010 or upon the earlier termination of the Holdings Merger Agreement. The Holdings supporting unitholders may terminate their obligations under the support agreement in certain circumstances, including specified changes in U.S. federal income tax law if such chang es occur prior to the closing of the merger.

In connection with the proposed merger, a privately held affiliate of EPCO has agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us on an initial amount of 30,610,000 of our common units (the "Designated Units") for a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver would apply is as follows for distributions to be paid during the following periods, if any: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015.

The Holdings Merger Agreement contains customary representations and warranties and covenants by each of the parties. Completion of the proposed merger is conditioned upon, among other things: (i) the absence of certain legal impediments prohibiting the transactions, (ii) applicable regulatory approvals and (iii) the conditions precedent contained in the Holdings Merger Agreement having been satisfied. The Holdings Merger Agreement contains provisions granting us and Holdings the right to terminate the agreement for certain reasons, including, among others, if the proposed merger does not occur on or before December 31, 2010.

***TEPPCO Merger and Basis of Presentation***

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, received 1.24 of our common units for each TEPPCO unit they owned. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. On October 27, 2009, our TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

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

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

Due to common control considerations, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. As a result, our consolidated financial statements and business segments were recast to reflect the TEPPCO Merger. Our recast consolidated financial statements for periods prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are presented as “Former owners of TEPPCO,” which is a component of noncontrolling interest. Investors should use our recast consolidated financial statements when making comparisons between our current and pr ior period financial information.

***Consolidation of Duncan Energy Partners***

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. 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 nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

***Deconsolidation of Texas Offshore Port System***

In August 2008, we, including TEPPCO, together with Oiltanking Holding Americas, Inc. (“Oiltanking”) formed the Texas Offshore Port System partnership (“TOPS”). In April 2009, we and TEPPCO dissociated from TOPS. As a result, our operating costs and expenses and net income for the second quarter of 2009 include a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment, including that of TEPPCO, in TOPS through the date of dissociation. The impact on net income attributable to Enterprise Products Partners L.P. was approximately $34.2 million, as $34.2 million of this loss was absorbed by noncontrolling interests in consolidation (i.e., by the former owners of TEPPCO).

We consolidated the financial statements of TOPS with those of our own since TEPPCO and we held a majority of the ownership interests and voting control of TOPS. Oiltanking’s interest in the joint venture was accounted for as a noncontrolling interest. As a result of our dissociation from TOPS, we discontinued the consolidation of TOPS during the second quarter of 2009. The effect of deconsolidation was to remove the accounts of TOPS, including Oiltanking’s noncontrolling interest of $33.4 million, from our books and records, after reflecting the $68.4 million aggregate write-off of the investments related to the deconsolidation.

In September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized approximately $66.9 million of expense during the third quarter of 2009 in connection with the payment of this cash settlement.

**Note 2. General Accounting Matters**

***Estimates***

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (e.g., assets, liabilities, revenue and expenses) and disclosures regarding 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. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

***Fair Value Information***

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses and other current liabilities (excluding derivative instruments) are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed-rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 4 for fair value information associated with our derivative instruments.

The following table presents the estimated fair values of our financial instruments at the dates indicated:

| | September 30, 2010 | | December 31, 2009 | |
|---|---|---|---|---|
| **Financial Instruments** | **Carrying Value** | **Fair Value** | **Carrying Value** | **Fair Value** |
| **Financial assets:** | | | | |
| Cash and cash equivalents and restricted cash | $ 75.2 | $ 75.2 | $ 118.3 | $ 118.3 |
| Accounts receivable | 3,067.6 | 3,067.6 | 3,137.4 | 3,137.4 |
| **Financial liabilities:** | | | | |
| Accounts payable and accrued expenses | 4,120.2 | 4,120.2 | 4,101.4 | 4,101.4 |
| Other current liabilities (excluding derivative instruments) | 338.9 | 338.9 | 341.6 | 341.6 |
| Fixed-rate debt (principal amount) | 12,032.7 | 13,205.5 | 10,586.7 | 11,056.2 |
| Variable-rate debt | 622.3 | 622.3 | 710.3 | 710.3 |

***Recent Accounting Developments***

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). IFRS consist of accounting standards published by the International Accounting Standards Board ("IASB"), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently, the Financial Accounting Standards Board (or "FASB," based in Norwalk, Connecticut) and the IASB are working both individually and jo intly on a number of accounting standard convergence projects that, if finalized in 2011, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, financial instruments, consolidations and fair value measurements.

The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS, with the expectation that any decision to adopt IFRS will allow U.S. issuers a number of years to transition from current U.S. GAAP. We continue to monitor developments regarding the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

***Restricted Cash***

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At September 30, 2010 and December 31, 2009, our restricted cash amounts were $32.5 million and $63.6 million, respectively. Our restricted cash balances have decreased since December 31, 2009 due to a reduction in margin requirements related to our commodity hedging activities. See Note 4 for information regarding our derivative instruments and hedging activities.

**Note 3. Equity-based Awards**

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the expense we recognized in connection with equity-based awards for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Restricted unit awards (1) | $ 9.1 | $ 4.2 | $ 22.0 | $ 10.4 |
| Unit option awards (1) | 1.1 | 0.7 | 2.9 | 1.4 |
| Unit appreciation rights (2) | 0.2 | 0.1 | 0.4 | 0.1 |
| Phantom units (2) | 0.1 | 0.1 | 0.2 | 0.2 |
| Profits interests awards (1) (3) | 17.7 | 1.9 | 21.3 | 5.3 |
| Total compensation expense | $ 28.2 | $ 7.0 | $ 46.8 | $ 17.4 |

(1) Accounted for as equity-classified awards.
(2) Accounted for as liability-classified awards.
(3) The increase between periods is due to the liquidation of the Employee Partnerships in August 2010 (see below).

The fair value of an equity-classified award (e.g., a restricted unit award) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At September 30, 2010, EPCO's long-term incentive plans applicable to our operations were the Enterprise Products 1998 Long-Term Incentive Plan, the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan and the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan. In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"). EPCO's equity-based awards also included profits interests in the Employee Partnerships until their liquidation in August 2010.

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 common units issued to the employee. In addition, we reimbursed EPCO for certain amounts recorded in connection with EPCO Unit (one of the Employee Partnerships). Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO would reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit. Except for the foregoing, we are not responsible for reimbursing EPCO for any of the costs associated with equity awards.

***Restricted Unit Awards***

Restricted unit awards allow recipients to acquire (at no cost to the recipient apart from service or other conditions) limited partner units once a defined vesting period expires, subject to customary forfeiture provisions. Restricted unit awards may be denominated in our common units or those of Duncan Energy

Partners depending on the issuer of the award. Restricted unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted unit awards are typically subject to graded vesting provisions in which one-fourth of each award vests on the first, second, third and fourth anniversaries of the date of grant. As used in the context of EPCO's long-term incentive plans, the term "restricted unit" represents a time-vested unit. Such awards are non-vested until the required service period expires.

The fair value of a restricted unit award is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents information regarding restricted unit awards for the periods indicated:

| | Number of Units | Weighted-Average Grant Date Fair Value per Unit (1) |
|---|---|---|
| **Enterprise Products Partners L.P. restricted unit awards:** | | |
| **Restricted units at December 31, 2009** | 2,720,882 | $ 27.70 |
| Granted (2,3) | 1,353,425 | $ 32.36 |
| Vested (3) | (339,628) | $ 25.26 |
| Forfeited | (103,558) | $ 29.54 |
| **Restricted units at September 30, 2010** | 3,631,121 | $ 29.61 |
| **Duncan Energy Partners L.P. restricted unit awards:** | | |
| **Restricted units at December 31, 2009** | -- | |
| Granted (3,4) | 6,348 | $ 25.26 |
| Vested (3) | (6,348) | $ 25.26 |
| **Restricted units at September 30, 2010** | -- | |

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued.
(2) Aggregate grant date fair value of restricted unit awards denominated in our common units was $43.8 million based on a grant date market price of our common units ranging from $32.00 to $38.36 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) Includes awards granted to the independent directors of the boards of directors of EPGP and DEP GP as part of their annual compensation for 2010. A total of 6,960 and 6,348 restricted unit awards were issued in February 2010 to the independent directors of EPGP and DEP GP, respectively, that immediately vested upon issuance.
(4) Aggregate grant date fair value of restricted unit awards denominated in Duncan Energy Partners' common units was $0.2 million based on a grant date market price of Duncan Energy Partners' common units of $25.26 per unit.

In the aggregate, unrecognized compensation cost of restricted unit awards was $53.2 million at September 30, 2010, of which our allocated share of the cost is currently estimated to be $46.2 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

***Unit Option Awards***

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These option awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. When issued, the exercise price of each option award may be no less than the market price of the underlying security on the date of grant. In general, option awards have a vesting period of four years from the date of grant. If option awards are not exercised, these awards generally expire between five and ten years after the date of grant.

The fair value of each unit option is estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of the underlying security, and expected unit price volatility.

Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the vesting period.

The following table presents unit option activity for the periods indicated. As of September 30, 2010, only Enterprise Products Partners has issued unit option awards.

| | Number of Units | Weighted-Average Strike Price (dollars/unit) | Weighted-Average Remaining Contractual Term (in years) | Aggregate Intrinsic Value (1) |
|---|---|---|---|---|
| **Unit options at December 31, 2009** | 3,825,920 | $ 26.52 | | |
| Granted (2) | 785,000 | $ 32.26 | | |
| Exercised | (812,500) | $ 25.01 | | |
| **Unit options at September 30, 2010** | 3,798,420 | $ 28.03 | 3.9 | $ 0.7 |
| **Options exercisable at September 30, 2010** | 45,000 | $ 24.30 | 4.4 | $ 0.7 |

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options was $2.3 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $32.26 per unit; (ii) weighted-average expected life of options of 4.9 years; (iii) weighted-average risk-free interest rate of 2.5%; (iv) weighted-average expected distribution yield on our common units of 6.9%; and (v) weighted-average expected unit price volatility on our common units of 23.3%. An estimated forfeiture rate of 17% was applied to awards granted during 2010.

The following table presents additional information regarding unit option awards for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Total intrinsic value of option awards exercised during period | $ 7.5 | $ 0.3 | $ 9.7 | $ 0.6 |
| Cash received from EPCO in connection with the exercise of unit option awards | 5.0 | 0.3 | 6.6 | 0.5 |
| Unit option-related reimbursements to EPCO | 7.5 | 0.2 | 9.7 | 0.5 |

In the aggregate, unrecognized compensation cost of unit option awards was $8.5 million at September 30, 2010, of which our allocated share of the cost is currently estimated to be $7.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.5 years.

***Unit Appreciation Rights***

UARs entitle a participant to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of the underlying security (determined as of a future vesting date) over the grant date fair value of the award. UARs are accounted for as liability awards. The following tables present information regarding UARs for the periods indicated:

| | UARs Based on Units of | | |
|---|---|---|---|
| | Enterprise Products Partners | Holdings | Total |
| **UARs at December 31, 2009** | 142,196 | 90,000 | 232,196 |
| Settled or forfeited | (10,255) | -- | (10,255) |
| **UARs at September 30, 2010** | 131,941 | 90,000 | 221,941 |

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| **Accrued liability for UARs** | $ 0.8 | $ 0.3 |

At September 30, 2010, 131,941 UARs had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf. These awards are subject to five-year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on a unit price of $37.00 for our common units. If the employee resigns prior to vesting, the UARs are forfeited.

At September 30, 2010, there were 90,000 UARs outstanding that were granted to the independent directors of DEP GP. These UARs cliff vest in 2012. The grant date fair value with respect to these UARs is based on a Holdings' unit price of $36.68. If a director resigns prior to vesting, his UARs are forfeited.

***Phantom Unit Awards***

Certain of EPCO's long-term incentive plans provide for the issuance of phantom unit awards. These awards are automatically redeemed for cash based on the fair value of the vested portion of phantom units at redemption dates stated in each award. The fair value of each phantom unit award is equal to the closing market price of the underlying security on the redemption date. Each participant is required to redeem their phantom unit awards as they vest, which is typically three to four years from the date the award is granted. Phantom unit awards are accounted for as liability awards.

The following tables present information regarding phantom unit awards for the periods indicated:

| | |
|---|---|
| **Phantom unit awards at December 31, 2009** | 14,927 |
| Granted | 6,200 |
| Vested (1) | (4,327) |
| **Phantom unit awards at September 30, 2010** | 16,800 |

(1) Primarily consists of 3,472 phantom unit awards outstanding under the TEPPCO 1999 Phantom Unit Retention Plan at December 31, 2009, which vested in January 2010. The plan was subsequently terminated.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2010** | **2009** | **2010** | **2009** |
| **Liabilities paid for phantom unit awards** | $ -- | $ -- | $ 0.1 | $ 1.1 |

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| **Accrued liability for phantom unit awards** | $ 0.3 | $ 0.2 |

***Profits Interests Awards***

As long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in the Employee Partnerships. These partnerships were liquidated in August 2010. Prior to liquidation, the profits interests awards entitled each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. Each Employee Partnership owned either our common units or Holdings' units or a combination of both. During the three months ended September 30, 2010, we recognized approximately $23 million of expense in connection with the liquidation of the Employee Partnerships. Of this expense amount, approximately $17 million was non-cash.

**Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements**

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced sale. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

§ Foreign currency exposure - A foreign currency hedge can be treated as either a fair value hedge or a cash flow hedge depending on the risk being hedged.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transac tions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

***Interest Rate Derivative Instruments***

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at September 30, 2010:

| Hedged Transaction | Number and Type of Derivative(s) Employed | Notional Amount | Period of Hedge | Rate Swap | Accounting Treatment |
|---|---|---|---|---|---|
| Senior Notes C | 1 fixed-to-floating swap | $100.0 | 1/04 to 2/13 | 6.4% to 2.6% | Fair value hedge |
| Senior Notes G | 3 fixed-to-floating swaps | $300.0 | 10/04 to 10/14 | 5.6% to 1.4% | Fair value hedge |
| Senior Notes P | 7 fixed-to-floating swaps | $400.0 | 6/09 to 8/12 | 4.6% to 2.7% | Fair value hedge |

In September 2010, Duncan Energy Partners’ three floating-to-fixed swaps with a notional amount of $175.0 million expired.

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for a fixed or floating interest rate stipulated in the derivative instrument.  Our interest rate swaps associated with existing debt obligations resulted in a decrease in interest expense of $3.7 million and an increase in interest expense of $1.2 million for the three months ended September 30, 2010 and 2009, respectively.  For the nine months ended September 30, 2010 and 2009, such swaps resulted in a decrease in interest expense of $12.6 million and an increase in interest expense of $1.4 million, respectively.

The following table summarizes our forward starting interest rate swaps outstanding at September 30, 2010, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt:

| Hedged Transaction | Number and Type of Derivatives Employed | Notional Amount | Expected Termination Date | Average Rate Locked | Accounting Treatment |
|---|---|---|---|---|---|
| Future debt offering | 3 forward starting swaps | $250.0 | 2/11 | 3.7% | Cash flow hedge |
| Future debt offering | 10 forward starting swaps | $500.0 | 2/12 | 4.5% | Cash flow hedge |
| Future debt offering | 3 forward starting swaps | $150.0 | 8/12 | 4.0% | Cash flow hedge |
| Future debt offering | 16 forward starting swaps | $1,000.0 | 3/13 | 3.7% | Cash flow hedge |

In May 2010, we settled a forward starting swap with a notional amount of $50.0 million and recognized a gain of $1.3 million in other comprehensive income.  This amount will be amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt.

***Commodity Derivative Instruments***

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our commodity derivative instruments outstanding at September 30, 2010:

| | Volume (1) | | Accounting |
|---|---|---|---|
| **Derivative Purpose** | **Current** | **Long-Term (2)** | **Treatment** |
| **Derivatives designated as hedging instruments:** | | | |
| **Enterprise Products Partners:** | | | |
| Natural gas processing: | | | |
| Forecasted natural gas purchases for plant thermal reduction ("PTR") (3) | 19.0 Bcf | n/a | Cash flow hedge |
| Forecasted sales of NGLs (4) | 5.1 MMBbls | n/a | Cash flow hedge |
| Octane enhancement: | | | |
| Forecasted purchases of NGLs | 0.8 MMBbls | n/a | Cash flow hedge |
| Forecasted sales of NGLs | 0.1 MMBbls | n/a | Cash flow hedge |
| Forecasted sales of octane enhancement products | 1.4 MMBbls | n/a | Cash flow hedge |
| Natural gas marketing: | | | |
| Natural gas storage inventory management activities | 3.8 Bcf | n/a | Fair value hedge |
| NGL marketing: | | | |
| Forecasted purchases of NGLs and related hydrocarbon products | 10.4 MMBbls | 0.7 MMBbls | Cash flow hedge |
| Forecasted sales of NGLs and related hydrocarbon products | 13.5 MMBbls | 1.0 MMBbls | Cash flow hedge |
| Crude oil marketing: | | | |
| Forecasted purchases of crude oil | 3.0 MMBbls | n/a | Cash flow hedge |
| Forecasted sales of crude oil | 4.3 MMBbls | n/a | Cash flow hedge |
| **Duncan Energy Partners:** | | | |
| Forecasted sales of natural gas | 1.0 Bcf | n/a | Cash flow hedge |
| **Derivatives not designated as hedging instruments:** | | | |
| **Enterprise Products Partners:** | | | |
| Natural gas risk management activities (5,6) | 526.8 Bcf | 62.2 Bcf | Mark-to-market |
| NGL risk management activities (6) | 0.7 MMBbls | n/a | Mark-to-market |
| Crude oil risk management activities (6) | 1.0 MMBbls | n/a | Mark-to-market |
| **Duncan Energy Partners:** | | | |
| Natural gas risk management activities (6) | 1.0 Bcf | n/a | Mark-to-market |

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives included in the long-term column is December 2012.

(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.

(4) Excludes 1.5 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements under current accounting guidance. The combination of these volumes with the 5.1 MMBbls reflected as derivatives in the table above results in a total of 6.6 MMBbls of hedged forecasted NGL sales volumes, which corresponds to the 19.0 Bcf of forecasted natural gas purchase volumes for PTR.

(5) Current and long-term volumes include approximately 149.7 and 10.5 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.

(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through June 2011, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

§ The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

***Foreign Currency Derivative Instruments***

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency values between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in an exchange rate. Prior to the third quarter of 2010, long-term transactions (i.e., those having terms of more than two months) were accounted for as cash flow hedges and shorter term transactions were accounted for using mark-to-market accounting. We currently account for all foreign currency derivative transactions using mark-to-market accounting. At September 30, 2010, our foreign currency derivative instruments portfolio had a notional amount of $7.0 million Canadian. The fair market value of these derivative instruments was an asset of $0.1 million at September 30, 2010.

***Credit-Risk Related Contingent Features in Derivative Instruments***

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At September 30, 2010, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $2.5 million, all of which was subject to a credit rating continge nt feature. If our credit ratings were downgraded to Ba3/BB- or below, approximately $2.5 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity positions and prices fluctuate.

***Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items***

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

| | Asset Derivatives | | | | Liability Derivatives | | | |
|---|---|---|---|---|---|---|---|---|
| | September 30, 2010 | | December 31, 2009 | | September 30, 2010 | | December 31, 2009 | |
| | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value |
| **Derivatives designated as hedging instruments** | | | | | | | | |
| Interest rate derivatives | Other current assets | $ 30.8 | Other current assets | $ 32.7 | Other current liabilities | $ 22.1 | Other current liabilities | $ 5.5 |
| Interest rate derivatives | Other assets | 38.6 | Other assets | 31.8 | Other liabilities | 101.3 | Other liabilities | 2.2 |
| **Total interest rate derivatives** | | 69.4 | | 64.5 | | 123.4 | | 7.7 |
| Commodity derivatives | Other current assets | 29.9 | Other current assets | 52.0 | Other current liabilities | 63.8 | Other current liabilities | 62.6 |
| Commodity derivatives | Other assets | 2.7 | Other assets | 0.5 | Other liabilities | 2.9 | Other liabilities | 1.8 |
| **Total commodity derivatives** (1) | | 32.6 | | 52.5 | | 66.7 | | 64.4 |
| Foreign currency derivatives | Other current assets | -- | Other current assets | 0.2 | Other current liabilities | -- | Other current liabilities | -- |
| **Total derivatives designated as hedging instruments** | | $ 102.0 | | $ 117.2 | | $ 190.1 | | $ 72.1 |
| **Derivatives not designated as hedging instruments** | | | | | | | | |
| Commodity derivatives | Other current assets | $ 50.7 | Other current assets | $ 28.9 | Other current liabilities | $ 45.7 | Other current liabilities | $ 24.9 |
| Commodity derivatives | Other assets | 3.9 | Other assets | 2.0 | Other liabilities | 8.1 | Other liabilities | 2.7 |
| **Total commodity derivatives** | | 54.6 | | 30.9 | | 53.8 | | 27.6 |
| Foreign currency derivatives | Other assets | 0.1 | Other assets | -- | Other liabilities | -- | Other liabilities | -- |
| **Total derivatives not designated as hedging instruments** | | $ 54.7 | | $ 30.9 | | $ 53.8 | | $ 27.6 |

(1) Represents commodity derivative instrument transactions that have either 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.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

| Derivatives in Fair Value Hedging Relationships | Location | Gain/(Loss) Recognized in Income on Derivative | | | |
|---|---|---|---|---|---|
| | | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | | 2010 | 2009 | 2010 | 2009 |
| Interest rate derivatives | Interest expense | $ 8.1 | $ 12.0 | $ 27.1 | $ (4.2) |
| Commodity derivatives | Revenue | 6.1 | 0.6 | 9.0 | (0.1) |
| Total | | $ 14.2 | $ 12.6 | $ 36.1 | $ (4.3) |

| Derivatives in Fair Value Hedging Relationships | Location | Gain/(Loss) Recognized in Income on Hedged Item | | | |
|---|---|---|---|---|---|
| | | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | | 2010 | 2009 | 2010 | 2009 |
| Interest rate derivatives | Interest expense | $ (8.6) | $ (14.5) | $ (26.8) | $ 1.1 |
| Commodity derivatives | Revenue | (7.0) | (0.5) | (9.4) | 0.6 |
| Total | | $ (15.6) | $ (15.0) | $ (36.2) | $ 1.7 |

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Comprehensive Income and Consolidated Operations for the periods indicated.

| Derivatives in Cash Flow Hedging Relationships | Change in Value Recognized in Other Comprehensive Income on Derivative (Effective Portion) | | | |
|---|---|---|---|---|
| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| Interest rate derivatives (1) | $ (65.5) | $ (8.0) | $ (142.0) | $ 7.1 |
| Commodity derivatives – Revenue | (44.2) | (21.3) | 42.2 | 44.5 |
| Commodity derivatives – Operating costs and expenses | (19.9) | 13.0 | (73.2) | (191.4) |
| Foreign currency derivatives | 0.1 | 0.2 | (0.1) | (10.3) |
| Total | $ (129.5) | $ (16.1) | $ (173.1) | $ (150.1) |

(1) Change in value due to increased notional amounts of forward starting swaps and the reduction of London Interbank Offered Rates ("LIBOR").

| Derivatives in Cash Flow Hedging Relationships | Location | Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/Loss to Income (Effective Portion) | | | |
|---|---|---|---|---|---|
| | | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | | 2010 | 2009 | 2010 | 2009 |
| Interest rate derivatives | Interest expense | $ (3.2) | $ (2.8) | $ (9.8) | $ (7.6) |
| Commodity derivatives | Revenue | 39.2 | (12.5) | 41.7 | 7.2 |
| Commodity derivatives | Operating costs and expenses | (13.6) | (65.3) | (31.1) | (183.5) |
| Foreign currency derivatives | Other income | -- | -- | 0.3 | -- |
| Total | | $ 22.4 | $ (80.6) | $ 1.1 | $ (183.9) |

| Derivatives in Cash Flow Hedging Relationships | Location | Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative | | | |
|---|---|---|---|---|---|
| | | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | | 2010 | 2009 | 2010 | 2009 |
| Commodity derivatives | Revenue | $ -- | $ 0.8 | $ -- | $ 0.1 |
| Commodity derivatives | Operating costs and expenses | (0.4) | (1.0) | 2.5 | (2.3) |
| Total | | $ (0.4) | $ (0.2) | $ 2.5 | $ (2.2) |

Over the next twelve months, we expect to reclassify $5.7 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $40.7 million of losses attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $21.9 million as an increase in operating costs and expenses and $18.8 million as a decrease in revenues.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

| Derivatives Not Designated as Hedging Instruments | Location | Gain/(Loss) Recognized in Income on Derivative | | | |
|---|---|---|---|---|---|
| | | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | | 2010 | 2009 | 2010 | 2009 |
| Commodity derivatives | Revenue | $ 17.0 | $ (5.4) | $ 12.0 | $ 26.7 |
| Commodity derivatives | Operating costs and expenses | -- | -- | (1.5) | -- |
| Foreign currency derivatives | Other income | 0.1 | -- | 0.1 | (0.1) |
| Total | | $ 17.1 | $ (5.4) | $ 10.6 | $ 26.6 |

***Fair Value Measurements***

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

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

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

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

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date.  Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies.  Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures.  Substantially all of these assumptions are: (i) observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals).  Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments.  The fair values of these derivative instruments are based on observable price quotes for similar products and locations.  The fair value of our interest rate derivatives are determined using appropriate financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest swap settlements.

§ Level 3 fair values are based on unobservable inputs.  Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.  Unobservable inputs reflect our 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 to us in the circumstances, which might include our internally developed data.  Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value.  Our Level 3 fair values primarily consi st of ethane, normal butane and natural gasoline-based contracts with terms ranging from two months to a year.  We rely on price quotes from reputable brokers who publish price quotes on certain products.  Whenever possible, we compare these prices to other reputable brokers for the same product in the same market. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities at September 30, 2010. These financial assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input that is significant to their respective fair value measurements. Our assessment of the relative significance of such inputs requires judgment. There were no significant transfers between Levels 1, 2 or 3 during the nine months ended September 30, 2010.

| | At September 30, 2010 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| **Financial assets:** | | | | |
| Interest rate derivatives | $ -- | $ 69.4 | $ -- | $ 69.4 |
| Commodity derivatives | 32.7 | 37.1 | 17.4 | 87.2 |
| Foreign currency derivatives | -- | 0.1 | -- | 0.1 |
| Total | $ 32.7 | $ 106.6 | $ 17.4 | $ 156.7 |
| | | | | |
| **Financial liabilities:** | | | | |
| Interest rate derivatives | $ -- | $ 123.4 | $ -- | $ 123.4 |
| Commodity derivatives | 56.1 | 37.5 | 26.9 | 120.5 |
| Total | $ 56.1 | $ 160.9 | $ 26.9 | $ 243.9 |

The following table sets forth a reconciliation of changes in the overall fair values of our Level 3 financial assets and liabilities for the periods indicated:

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | 2010 | 2009 |
| **Balance, January 1** | $ 5.7 | $ 32.4 |
| Total gains (losses) included in: | | |
| Net income (1) | (3.6) | 12.9 |
| Other comprehensive income (loss) | (8.3) | 1.5 |
| Purchases, issuances, settlements – net | 3.6 | (12.3) |
| **Balance, March 31** | (2.6) | 34.5 |
| Total gains (losses) included in: | | |
| Net income (1) | 16.2 | 7.7 |
| Other comprehensive income (loss) | 22.2 | (23.1) |
| Purchases, issuances, settlements – net | (16.2) | (8.1) |
| Transfers out of Level 3 | 0.2 | (0.2) |
| **Balance, June 30** | 19.8 | 10.8 |
| Total gains (losses) included in: | | |
| Net income (1) | 18.2 | 7.6 |
| Other comprehensive income (loss) | (31.4) | (10.1) |
| Purchases, issuances, settlements – net | (16.1) | (6.7) |
| Transfers out of Level 3 | -- | (2.3) |
| **Balance, September 30** | $ (9.5) | $ (0.7) |

(1) There were $6.4 million and $4.1 million of unrealized gains included in these amounts for the three and nine months ended September 30, 2010, respectively. There were $3.3 million and $3.5 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2009, respectively.

***Nonfinancial Assets and Liabilities***

During the nine months ended September 30, 2010, certain pipeline assets recorded as property, plant and equipment were adjusted to fair value based on the present value of expected future cash flows (Level 3), resulting in nonrecurring fair value adjustments (i.e., non-cash asset impairment charges) totaling $1.5 million.

During the nine months ended September 30, 2009, certain river terminal and marine barge assets recorded as property, plant and equipment and other current assets were adjusted to fair value based on the present value of expected future cash flows (Level 3), resulting in non-cash asset impairment charges of $25.0 million. In addition, we recorded an impairment charge of $1.3 million related to goodwill during this period. These impairment charges resulted from reduced levels of throughput at the affected river terminals, the indefinite suspension of expansion plans for certain river terminals, and the determination that an underground gas storage cavern and certain marine transportation barges were obsolete. The affected river terminals were subject to a throughput contract with a third party.  60;See Note 15 for information regarding a related $28.7 million charge for deficiency fees related to the reduced levels of throughput at the affected river terminals.

The impairment charges we recorded during the nine months ended September 30, 2010 and 2009 are a component of operating costs and expenses.

**Note 5. Inventories**

Our inventory amounts were as follows at the dates indicated:

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| Working inventory (1) | $ 788.9 | $ 466.4 |
| Forward sales inventory (2) | 421.1 | 245.5 |
| Total inventory | $ 1,210.0 | $ 711.9 |

(1) Working inventory is comprised of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are either available-for-sale or used in the provision for services. The increase since December 31, 2009 is primarily related to increased marketing activities of refined products.
(2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts. The increase since December 31, 2009 is primarily related to higher refined products forward sales volumes.

In those instances where we take ownership of inventory 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-based prices during the month in which they are acquired.

The following table presents our cost of sales and lower of cost or market (“LCM”) adjustments for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Cost of sales (1) | $ 6,814.0 | $ 5,581.3 | $ 20,499.5 | $ 13,820.1 |
| LCM adjustments | 0.2 | 0.5 | 7.1 | 6.2 |

(1) Cost of sales is a component of “Operating costs and expenses,” as presented on our Unaudited Condensed Statements of Consolidated Operations. Period-to-period fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

**Note 6.  Property, Plant and Equipment**

Our property, plant and equipment values and related accumulated depreciation balances were as follows at the dates indicated:

| | Estimated Useful Life in Years | September 30, 2010 | December 31, 2009 |
|---|---|---|---|
| Plants and pipelines (1) | 3-45 (6) | $ 18,869.7 | $ 17,681.9 |
| Underground and other storage facilities (2) | 5-40 (7) | 1,426.6 | 1,280.5 |
| Platforms and facilities (3) | 20-31 | 637.6 | 637.6 |
| Transportation equipment (4) | 3-10 | 102.6 | 60.1 |
| Marine vessels (5) | 15-30 | 599.8 | 559.4 |
| Land | | 91.7 | 82.9 |
| Construction in progress | | 1,467.7 | 1,207.2 |
| Total | | 23,195.7 | 21,509.6 |
| Less accumulated depreciation | | 4,385.7 | 3,820.4 |
| Property, plant and equipment, net | | $ 18,810.0 | $ 17,689.2 |

(1) Plants and pipelines include processing plants; NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets located in the Gulf of Mexico.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) Marine vessels include tow and push boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

In May 2010, we recorded approximately $293.4 million of property, plant and equipment in connection with the acquisition of the State Line and Fairplay natural gas gathering systems from subsidiaries of M2 Midstream LLC ("Momentum").  See Note 8 for additional information regarding this business combination.

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

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Depreciation expense (1) | $ 184.9 | $ 174.8 | $ 552.9 | $ 502.7 |
| Capitalized interest (2) | 12.5 | 11.4 | 33.5 | 39.5 |

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed 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.

Operating costs and expenses for the three and nine months ended September 30, 2010 include $9.9 million of non-cash charges resulting from the disposition of two pipeline segments in south Texas that were in natural gas gathering service.

***Asset Retirement Obligations***

We record asset retirement obligations ("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, 2009:

| | | |
|---|---|---|
| **ARO liability balance, December 31, 2009** | $ | 54.8 |
| Revisions in estimated cash flows | | 14.4 |
| Accretion expense | | 3.0 |
| Liabilities incurred during period | | 0.1 |
| Liabilities settled during period | | (8.1) |
| **ARO liability balance, September 30, 2010** | $ | 64.2 |

Property, plant and equipment at September 30, 2010 and December 31, 2009 includes $29.7 million and $26.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived assets. The following table presents forecasted accretion expense associated with our AROs for the periods indicated:

| Remainder of 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| $ 1.0 | $ 4.1 | $ 4.3 | $ 4.6 | $ 5.0 |

Certain of our unconsolidated affiliates had AROs recorded at September 30, 2010 and December 31, 2009 relating to contractual agreements and regulatory requirements. These amounts were immaterial to our consolidated financial statements.

**Note 7. Investments in Unconsolidated Affiliates**

We hold ownership interests in a number of midstream energy businesses that are accounted for using the equity method of accounting. The following table presents our investments in unconsolidated affiliates (according to the business segment to which they relate) and our ownership interests at the dates indicated:

| | Ownership Interest at September 30, 2010 | September 30, 2010 | December 31, 2009 |
|---|---|---|---|
| **NGL Pipelines & Services:** | | | |
| Venice Energy Service Company, L.L.C. | 13.1% | $ 31.8 | $ 32.6 |
| K/D/S Promix, L.L.C. (“Promix”) | 50% | 45.1 | 48.9 |
| Baton Rouge Fractionators LLC | 32.2% | 22.0 | 22.2 |
| Skelly-Belvieu Pipeline Company, L.L.C. | 50% | 33.8 | 37.9 |
| **Onshore Natural Gas Pipelines & Services:** | | | |
| Evangeline (1) | 49.5% | 6.1 | 5.6 |
| White River Hub, LLC | 50% | 26.5 | 26.4 |
| **Onshore Crude Oil Pipelines & Services:** | | | |
| Seaway Crude Pipeline Company (“Seaway”) | 50% | 174.7 | 178.5 |
| **Offshore Pipelines & Services:** | | | |
| Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”) | 36% | 58.8 | 61.7 |
| Cameron Highway Oil Pipeline Company | 50% | 233.3 | 239.6 |
| Deepwater Gateway, L.L.C. | 50% | 99.1 | 101.8 |
| Neptune Pipeline Company, L.L.C. | 25.7% | 54.2 | 53.8 |
| **Petrochemical & Refined Products Services:** | | | |
| Baton Rouge Propylene Concentrator, LLC | 30% | 10.6 | 11.1 |
| Centennial Pipeline LLC (“Centennial”) | 50% | 65.1 | 66.7 |
| Other (2) | Various | 3.6 | 3.8 |
| Total | | $ 864.7 | $ 890.6 |

(1) Evangeline refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. The following table presents the unamortized excess cost amounts by business segment at the dates indicated:

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| NGL Pipelines & Services | $ 25.9 | $ 27.1 |
| Onshore Crude Oil Pipelines & Services | 19.9 | 20.4 |
| Offshore Pipelines & Services | 16.4 | 17.3 |
| Petrochemical & Refined Products Services | 3.0 | 4.0 |
| Total | $ 65.2 | $ 68.8 |

Such excess cost amounts are attributable to the underlying tangible and amortizable intangible assets of the related unconsolidated affiliates. We amortize the excess cost amounts (as a reduction in equity earnings) in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| NGL Pipelines & Services | $ 0.2 | $ 0.2 | $ 0.7 | $ 0.7 |
| Onshore Crude Oil Pipelines & Services | 0.1 | 0.1 | 0.5 | 0.5 |
| Offshore Pipelines & Services | 0.3 | 0.3 | 0.9 | 0.9 |
| Petrochemical & Refined Products Services | 0.1 | 1.0 | 1.0 | 3.0 |
| Total | $ 0.7 | $ 1.6 | $ 3.1 | $ 5.1 |

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| NGL Pipelines & Services | $ 5.1 | $ 4.0 | $ 12.1 | $ 7.5 |
| Onshore Natural Gas Pipelines & Services | 1.2 | 1.4 | 3.4 | 3.9 |
| Onshore Crude Oil Pipelines & Services | 1.6 | 1.2 | 7.5 | 7.4 |
| Offshore Pipelines & Services | 10.1 | 10.6 | 33.0 | 22.1 |
| Petrochemical & Refined Products Services | (0.5) | (2.2) | (5.8) | (8.9) |
| Total | $ 17.5 | $ 15.0 | $ 50.2 | $ 32.0 |

***Summarized Income Statement Information of Unconsolidated Affiliates***

The following tables present unaudited income statement information (on a 100% basis) of our unconsolidated affiliates, aggregated by the business segments to which they relate, for the periods indicated:

| | Summarized Income Statement Information for the Three Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | September 30, 2010 | | | September 30, 2009 | | |
| | Revenues | Operating Income | Net Income | Revenues | Operating Income | Net Income |
| NGL Pipelines & Services | $ 78.3 | $ 17.3 | $ 17.3 | $ 60.0 | $ 10.9 | $ 11.2 |
| Onshore Natural Gas Pipelines & Services | 63.8 | 2.6 | 2.4 | 54.5 | 2.9 | 2.7 |
| Onshore Crude Oil Pipelines & Services | 16.6 | 5.8 | 5.8 | 20.7 | 6.9 | 6.8 |
| Offshore Pipelines & Services | 49.4 | 25.3 | 25.1 | 43.2 | 24.7 | 24.0 |
| Petrochemical & Refined Products Services | 15.1 | 2.5 | 0.2 | 12.8 | 2.4 | -- |

| | Summarized Income Statement Information for the Nine Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | September 30, 2010 | | | September 30, 2009 | | |
| | Revenues | Operating Income | Net Income (Loss) | Revenues | Operating Income | Net Income (Loss) |
| NGL Pipelines & Services | $ 227.8 | $ 43.8 | $ 43.7 | $ 161.7 | $ 23.7 | $ 24.2 |
| Onshore Natural Gas Pipelines & Services | 159.8 | 7.0 | 6.7 | 137.1 | 8.0 | 7.6 |
| Onshore Crude Oil Pipelines & Services | 57.1 | 23.9 | 23.9 | 62.2 | 25.6 | 25.6 |
| Offshore Pipelines & Services | 155.8 | 81.3 | 80.5 | 106.4 | 39.2 | 37.7 |
| Petrochemical & Refined Products Services | 39.3 | 0.5 | (6.6) | 41.1 | 5.2 | (2.5) |

**Note 8.  Business Combinations**

***State Line and Fairplay Natural Gas Gathering Systems***

In May 2010, we acquired 100% ownership of the State Line and Fairplay natural gas gathering systems and related assets from Momentum for approximately $1.2 billion in cash.  The effective date of the acquisition was May 1, 2010.  These systems are located in northwest Louisiana and east Texas and gather natural gas produced from the Haynesville/Bossier Shales and the Cotton Valley and Taylor Sand formations. We used a portion of the net proceeds from our April 2010 equity offering, together with borrowings under EPO's Multi-Year Revolving Credit Facility, to fund this acquisition.

The State Line system is located in Desoto and Caddo Parishes, Louisiana and Panola County, Texas.  The system currently includes approximately 188 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 700 million cubic feet per day ("MMcf/d") and two natural gas treating facilities.  The State Line system began operations in February 2009 and is currently gathering approximately 375 MMcf/d of natural gas.  The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas.  The system includes approximately 249 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 285 MMcf/d.  The Fairplay system is currently gathering approximately 150 MMcf/d of natural gas.   ;Our operations related to the Fairplay system include providing natural gas processing services using third-party processing facilities. The State Line and Fairplay systems are supported by long-term acreage dedication agreements totaling approximately 210,000 acres, as well as volumetric commitments from producers.

Our acquisition of the State Line system complements our Haynesville Extension natural gas pipeline project.  The Haynesville Extension, which is under development by Acadian Gas, LLC, is expected to provide shippers with takeaway capacity from the Haynesville Shale producing basin and flexible options for reaching attractive markets for their natural gas, including access to nine interstate gas pipeline systems.  The Fairplay system is expected to extend our asset base through planned future interconnects with our Texas Intrastate System, along with supporting deliveries of NGLs into our Panola pipeline and further to our fractionation, storage and distribution complex in Mont Belvieu, Texas.

On a combined basis, our consolidated revenues and net income from the State Line and Fairplay systems were $75.0 million and $8.1 million, respectively, for the five months we owned these assets.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

Pro forma financial information. Since the effective date of the State Line and Fairplay acquisitions was May 1, 2010, our Unaudited Condensed Statements of Consolidated Operations do not include earnings from these businesses prior to this date. The following table presents selected unaudited pro forma earnings information for the periods presented as if the acquisitions had been completed on January 1 of each year presented. This pro forma information was prepared using historical financial data for the State Line and Fairplay systems and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated fi nancial results would have been had we actually acquired the State Line and Fairplay systems on January 1 of each year presented.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Pro forma earnings data:** | | | | |
| Revenues | $ 8,067.8 | $ 6,823.7 | $ 24,221.1 | $ 17,199.5 |
| Costs and expenses | 7,516.1 | 6,480.5 | 22,597.0 | 16,021.2 |
| Operating income | 569.2 | 358.2 | 1,674.3 | 1,210.3 |
| Net income | 385.9 | 188.3 | 1,157.5 | 708.9 |
| Net income attributable to Enterprise Products Partners L.P. | 371.9 | 213.4 | 1,111.4 | 617.9 |
| | | | | |
| **Basic earnings per unit:** | | | | |
| As reported basic units outstanding | 638.0 | 464.3 | 629.9 | 458.4 |
| Pro forma basic units outstanding | 638.0 | 478.1 | 635.2 | 472.2 |
| As reported basic earnings per unit | $ 0.48 | $ 0.36 | $ 1.45 | $ 1.09 |
| Pro forma basic earnings per unit | $ 0.48 | $ 0.33 | $ 1.44 | $ 1.01 |
| **Diluted earnings per unit:** | | | | |
| As reported diluted units outstanding | 643.7 | 464.4 | 635.4 | 458.5 |
| Pro forma diluted units outstanding | 643.7 | 478.2 | 640.7 | 472.3 |
| As reported diluted earnings per unit | $ 0.47 | $ 0.36 | $ 1.44 | $ 1.09 |
| Pro forma diluted earnings per unit | $ 0.47 | $ 0.33 | $ 1.43 | $ 1.01 |

***Other 2010 Transactions***

In June 2010, we acquired a marine transportation business located in south Louisiana for $12.0 million in cash. This business is engaged in crude oil gathering and included three tug boats and five barges. This business is part of our Petrochemical & Refined Products Services business segment. In August 2010, we acquired a crude oil trucking business located in North Dakota for $4.0 million. This business is part of our Onshore Crude Oil Pipelines & Services business segment. On a pro forma consolidated basis after giving effect to these two transactions, 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 mater ially from those we reported for the three and nine months ended September 30, 2010 and 2009.

See Note 17 for information regarding a September 2010 drop down transaction whereby we acquired ownership interests in EPCO's trucking business.

***Purchase Price Allocations***

We accounted for our 2010 business combinations using the acquisition method of accounting. Accordingly, such costs have been allocated to assets acquired and liabilities assumed based on fair values that were developed using recognized business valuation techniques. The following table depicts the allocation of the fair value of assets acquired and liabilities assumed at the effective date for each business combination:

| | State Line and Fairplay Systems | Other | Total |
|---|---|---|---|
| **Assets acquired in business combination:** | | | |
| Current assets | $ -- | $ 1.6 | $ 1.6 |
| Property, plant and equipment, net | 293.4 | 10.1 | 303.5 |
| Identifiable intangible assets | 895.0 | -- | 895.0 |
| Total assets acquired | 1,188.4 | 11.7 | 1,200.1 |
| **Liabilities assumed in business combination:** | | | |
| Current liabilities | -- | (0.1) | (0.1) |
| Long-term debt | -- | (1.3) | (1.3) |
| Other long-term liabilities | (0.1) | -- | (0.1) |
| Total liabilities assumed | (0.1) | (1.4) | (1.5) |
| Total assets acquired plus liabilities assumed | 1,188.3 | 10.3 | 1,198.6 |
| Total cash used for business combinations | 1,214.5 | 18.5 | 1,233.0 |
| **Goodwill** (see Note 9) | $ 26.2 | $ 8.2 | $ 34.4 |

The State Line and Fairplay property, plant and equipment assets are a component of our Onshore Natural Gas Pipelines & Services business segment. Of the $895.0 million of identifiable intangible assets (i.e., customer relationships) we recorded in connection with this acquisition, $103.4 million is attributable to natural gas processing activities and $791.6 million to natural gas gathering operations. We classify earnings and assets associated with natural gas processing activities as part of our NGL Pipelines & Services segment. Earnings and assets associated with natural gas gathering activities are reported within our Onshore Natural Gas Pipelines & Services segment. See Note 9 for additional information regarding the customer relationship intangible assets we acquired in co nnection with the State Line and Fairplay systems.

**Note 9. Intangible Assets and Goodwill**

***Identifiable Intangible Assets***

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

| | September 30, 2010 | | | December 31, 2009 | | |
|---|---|---|---|---|---|---|
| | Gross Value | Accum. Amort. | Carrying Value | Gross Value | Accum. Amort. | Carrying Value |
| **NGL Pipelines & Services:** | | | | | | |
| Customer relationship intangibles (1) | $ 340.8 | $ (101.3) | $ 239.5 | $ 237.4 | $ (86.5) | $ 150.9 |
| Contract-based intangibles | 321.9 | (171.7) | 150.2 | 321.4 | (156.7) | 164.7 |
| Segment total | 662.7 | (273.0) | 389.7 | 558.8 | (243.2) | 315.6 |
| **Onshore Natural Gas Pipelines & Services:** | | | | | | |
| Customer relationship intangibles (1) | 1,163.6 | (149.1) | 1,014.5 | 372.0 | (124.3) | 247.7 |
| Contract-based intangibles | 565.3 | (313.4) | 251.9 | 565.3 | (285.8) | 279.5 |
| Segment total | 1,728.9 | (462.5) | 1,266.4 | 937.3 | (410.1) | 527.2 |
| **Onshore Crude Oil Pipelines & Services:** | | | | | | |
| Customer relationship intangibles | 9.6 | (3.7) | 5.9 | 9.6 | (3.4) | 6.2 |
| Contract-based intangibles | 0.4 | (0.1) | 0.3 | 0.4 | (0.1) | 0.3 |
| Segment total | 10.0 | (3.8) | 6.2 | 10.0 | (3.5) | 6.5 |
| **Offshore Pipelines & Services:** | | | | | | |
| Customer relationship intangibles | 205.8 | (115.0) | 90.8 | 205.8 | (105.3) | 100.5 |
| Contract-based intangibles | 1.2 | (0.2) | 1.0 | 1.2 | (0.2) | 1.0 |
| Segment total | 207.0 | (115.2) | 91.8 | 207.0 | (105.5) | 101.5 |
| **Petrochemical & Refined Products Services:** | | | | | | |
| Customer relationship intangibles | 104.7 | (22.5) | 82.2 | 104.6 | (18.8) | 85.8 |
| Contract-based intangibles | 41.7 | (17.7) | 24.0 | 42.1 | (13.9) | 28.2 |
| Segment total | 146.4 | (40.2) | 106.2 | 146.7 | (32.7) | 114.0 |
| Total all segments | $ 2,755.0 | $ (894.7) | $ 1,860.3 | $ 1,859.8 | $ (795.0) | $ 1,064.8 |

(1) In May 2010, we acquired $895.0 million of customer relationship intangible assets in connection with the State Line and Fairplay natural gas gathering systems. See Note 8 for additional information regarding this business combination.

The following table presents amortization expense related to our intangible assets for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| NGL Pipelines & Services | $ 10.4 | $ 9.4 | $ 29.8 | $ 27.6 |
| Onshore Natural Gas Pipelines & Services | 20.1 | 13.9 | 52.4 | 43.4 |
| Onshore Crude Oil Pipelines & Services | 0.1 | 0.1 | 0.3 | 0.3 |
| Offshore Pipelines & Services | 3.1 | 3.6 | 9.7 | 11.2 |
| Petrochemical & Refined Products Services | 2.7 | 2.7 | 7.9 | 8.0 |
| Total | $ 36.4 | $ 29.7 | $ 100.1 | $ 90.5 |

The following table presents our forecast of amortization expense associated with existing intangible assets for the years presented:

| Remainder of 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| $ 36.0 | $ 143.7 | $ 135.3 | $ 135.0 | $ 137.0 |

In general, our intangible assets fall within two categories: customer relationships and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used.

*Customer relationship intangible assets*. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At September 30, 2010, the carrying value of our customer relationship intangible assets was $1.43 billion.

In connection with our acquisition of the State Line and Fairplay natural gas gathering systems in May 2010, we acquired $895.0 million of customer relationship intangible assets. The acquired customer relationships as of September 30, 2010 are presented in the following table:

| | Gross Value | Accum. Amort. | Carrying Value |
|---|---|---|---|
| State Line natural gas gathering customer relationships (1) | $ 675.0 | $ (7.4) | $ 667.6 |
| Fairplay natural gas gathering customer relationships (1) | 116.6 | (2.7) | 113.9 |
| Fairplay natural gas processing customer relationships (2) | 103.4 | (2.4) | 101.0 |
| Total acquired customer relationships | $ 895.0 | $ (12.5) | $ 882.5 |

(1) These natural gas gathering customer relationship intangible assets are a component of our Onshore Natural Gas Pipelines & Services business segment.
(2) The Fairplay natural gas processing customer relationship intangible assets are a component of our NGL Pipelines & Services business segment.

In this context, a customer relationship is broadly defined as a relationship between the natural gas gathering system and the production fields from which it gathers natural gas. Natural gas gathering systems require a significant investment, both in terms of initial construction costs and ongoing maintenance. Investing the capital to construct a natural gas gathering system establishes access to producers in a particular field and represents a significant economic barrier effectively limiting competition (i.e. akin to a franchise). The low risk of competition ensures a long commercial relationship with existing customers as well as a high probability of commercial relationships with new producers in the field. As such, the relationship with producers is generally limited by the quantity an d production life of the underlying natural gas resource base.

The economic value we attribute to customer relationships acquired with the State Line and Fairplay systems was estimated using recognized business valuation techniques based on several key assumptions, which include assumptions regarding the renewal of existing contracts and natural gas resource bases. In general, natural gas is gathered on the State Line and Fairplay systems under long-term contracts, which include acreage dedications of approximately 110,000 acres and 100,000 acres, respectively, as well as volumetric commitments from certain natural gas producers on both systems. In addition, certain contracts related to the Fairplay system include natural gas processing services. Based on our experience as a provider of natural gas gathering and processing services, we anticipate the acquired cust omer relationships to extend well beyond the discrete term of existing contracts.

Customer relationship intangibles related to the State Line system have an estimated economic useful life of 27 years. The natural gas gathering and processing customer relationships associated with the Fairplay system have an estimated economic useful life of 23 years. Amortization expense is recorded using the units of production method based on gathering volumes. This method of amortization allows for expense to be recorded in a manner that closely resembles the pattern in which we benefit from natural gas gathering and processing services provided to customers. See Note 8 for additional information regarding this business combination.

Effective January 1, 2010, upon review of the future prospects for our Val Verde customer relationship intangible assets, management adjusted the amortization period to end in 2021. This change in estimate did not result in a material decrease in net income or earnings per unit for the three and nine months ended September 30, 2010.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At September 30, 2010, the carrying value of our contract-based intangible assets was $427.4 million.

***Goodwill***

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year. The following table presents changes in the carrying amount of goodwill for the periods presented:

| | NGL Pipelines & Services | Onshore Natural Gas Pipelines & Services | Onshore Crude Oil Pipelines & Services | Offshore Pipelines & Services | Petrochemical & Refined Products Services | Consolidated Totals |
|---|---|---|---|---|---|---|
| Balance at December 31, 2009 (1) | $ 341.2 | $ 284.9 | $ 303.0 | $ 82.1 | $ 1,007.1 | $ 2,018.3 |
| Goodwill related to acquisitions | -- | 26.2 | 8.2 | -- | -- | 34.4 |
| Balance at September 30, 2010 (1) | $ 341.2 | $ 311.1 | $ 311.2 | $ 82.1 | $ 1,007.1 | $ 2,052.7 |

(1) The total carrying amount of goodwill at September 30, 2010 and December 31, 2009 is presented net of $1.3 million of accumulated impairment charges included in our Petrochemical & Refined Products Services business segment.

In May 2010, we recorded $26.2 million of goodwill in connection with our acquisition of the State Line and Fairplay natural gas gathering systems. In June 2010, we recorded $6.1 million of goodwill related to our acquisition of a marine transportation business that provides crude oil gathering services in south Louisiana. In August 2010, we recorded $2.1 million of goodwill related to our acquisition of a crude oil trucking business based in North Dakota. We attribute these goodwill amounts to our ability to leverage the acquired businesses with our existing asset base to create future business opportunities.

Goodwill impairment testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the businesses contained within the reporting unit, which rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. Based on our most recent goodwill impairment tests, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

**Note 10. Debt Obligations**

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

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| EPO senior debt obligations: | | |
| Multi-Year Revolving Credit Facility, variable-rate, due November 2012 | $ 35.0 | $ 195.5 |
| Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010 | -- | 54.0 |
| Petal GO Zone Bonds, variable-rate, due August 2034 | 57.5 | 57.5 |
| Senior Notes B, 7.50% fixed-rate, due February 2011 (1) | 450.0 | 450.0 |
| Senior Notes C, 6.375% fixed-rate, due February 2013 | 350.0 | 350.0 |
| Senior Notes D, 6.875% fixed-rate, due March 2033 | 500.0 | 500.0 |
| Senior Notes G, 5.60% fixed-rate, due October 2014 | 650.0 | 650.0 |
| Senior Notes H, 6.65% fixed-rate, due October 2034 | 350.0 | 350.0 |
| Senior Notes I, 5.00% fixed-rate, due March 2015 | 250.0 | 250.0 |
| Senior Notes J, 5.75% fixed-rate, due March 2035 | 250.0 | 250.0 |
| Senior Notes K, 4.95% fixed-rate, due June 2010 | -- | 500.0 |
| Senior Notes L, 6.30% fixed-rate, due September 2017 | 800.0 | 800.0 |
| Senior Notes M, 5.65% fixed-rate, due April 2013 | 400.0 | 400.0 |
| Senior Notes N, 6.50% fixed-rate, due January 2019 | 700.0 | 700.0 |
| Senior Notes O, 9.75% fixed-rate, due January 2014 | 500.0 | 500.0 |
| Senior Notes P, 4.60% fixed-rate, due August 2012 | 500.0 | 500.0 |
| Senior Notes Q, 5.25% fixed-rate, due January 2020 | 500.0 | 500.0 |
| Senior Notes R, 6.125% fixed-rate, due October 2039 | 600.0 | 600.0 |
| Senior Notes S, 7.625% fixed-rate, due February 2012 | 490.5 | 490.5 |
| Senior Notes T, 6.125% fixed-rate, due February 2013 | 182.5 | 182.5 |
| Senior Notes U, 5.90% fixed-rate, due April 2013 | 237.6 | 237.6 |
| Senior Notes V, 6.65% fixed-rate, due April 2018 | 349.7 | 349.7 |
| Senior Notes W, 7.55% fixed-rate, due April 2038 | 399.6 | 399.6 |
| Senior Notes X, 3.70% fixed-rate, due June 2015 | 400.0 | -- |
| Senior Notes Y, 5.20% fixed-rate, due September 2020 | 1,000.0 | -- |
| Senior Notes Z, 6.45% fixed-rate, due September 2040 | 600.0 | -- |
| TEPPCO senior debt obligations: | | |
| TEPPCO Senior Notes | 40.1 | 40.1 |
| Duncan Energy Partners' debt obligations: | | |
| DEP Revolving Credit Facility, variable-rate, due February 2011 (1) | 247.5 | 175.0 |
| DEP Term Loan, variable-rate, due December 2011 | 282.3 | 282.3 |
| Total principal amount of senior debt obligations | 11,122.3 | 9,764.3 |
| EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 | 550.0 | 550.0 |
| EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 | 682.7 | 682.7 |
| EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 | 285.8 | 285.8 |
| TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067 | 14.2 | 14.2 |
| Total principal amount of senior and junior debt obligations | 12,655.0 | 11,297.0 |
| Other, non-principal amounts: | | |
| Change in fair value of debt-related derivative instruments (2) | 59.9 | 44.4 |
| Unamortized discounts, net of premiums | (24.4) | (18.7) |
| Unamortized deferred net gains related to terminated interest rate swaps (2) | 14.3 | 23.7 |
| Total other, non-principal amounts | 49.8 | 49.4 |
| Total long-term debt | $ 12,704.8 | $ 11,346.4 |

(1) Long-term and current maturities of debt reflect the classification of such obligations at September 30, 2010 after taking into consideration EPO's ability to use available forecast long-term borrowing capacity under its $1.75 billion Multi-Year Revolving Credit Facility to satisfy the current maturity of Senior Notes B and Duncan Energy Partners has the ability to use its available capacity after giving effect to the refinancing in October 2010 of its existing revolving credit facility on a long-term basis. See "— Debt Obligations — Duncan Energy Partners' debt obligations" below in this footnote.

(2) See Note 4 for information regarding our interest rate hedging activities.

***Letters of Credit***

At September 30, 2010, EPO had a $50.0 million letter of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding related to its Petal GO

Zone Bonds.  These letter of credit facilities do not reduce the amount available for borrowing under EPO's Multi-Year Revolving Credit Facility.

***Parent-Subsidiary Guarantor Relationships***

Enterprise Products Partners acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP Revolving Credit Facility, the DEP Term Loan and the remaining debt obligations of TEPPCO.  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.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt balances.  However, neither Enterprise Products Partners nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

***Debt Obligations***

Apart from that discussed below and routine fluctuations in the balance of our consolidated revolving credit facilities, there have been no significant changes in the terms of our consolidated debt obligations since those reported in our 2009 Form 10-K.

*Pascagoula MBFC Loan*.  This loan, from the Mississippi Business Finance Corporation ("MBFC"), matured in March 2010 and was repaid.

*Senior Notes X, Y and Z.*  In May 2010, EPO issued an aggregate of $2.0 billion in principal amount of senior unsecured notes.  EPO issued (i) $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes X") at 99.79% of their principal amount, (ii) $1.0 billion in principal amount of 10-year senior unsecured notes ("Senior Notes Y") at 99.701% of their principal amount and (iii) $600.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes Z") at 99.525% of their principal amount.  Net proceeds from the issuance of these senior notes were used (i) to repay EPO's Senior Note s K in June 2010, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.  EPO borrowed $850.0 million under its Multi-Year Revolving Credit Facility to fund a portion of the cash consideration paid to complete the State Line and Fairplay acquisitions in May 2010 (see Note 8).

Senior Notes X, Y and Z rank equal with EPO's existing and future unsecured and unsubordinated indebtedness.  They are senior to any existing and future subordinated indebtedness of EPO.  They are also 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.

*Duncan Energy Partners' debt obligations.*  On October 25, 2010, Duncan Energy Partners entered into new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion.  The new Duncan Energy Partners credit facilities mature in October 2013 and consist of (i) an $850.0 million multi-year revolving credit facility (the "DEP Multi-Year Revolving Credit Facility") and (ii) a $400.0 million term loan facility (the "DEP $400 Million Term Loan Facility").  At closing, Duncan Energy Partners borrowed the full amount available under the DEP $400 Million Term Loan Facility to repay amou nts outstanding under the DEP Revolving Credit Facility and an intercompany loan with EPO (eliminated in consolidation).  Upon repayment, the DEP Revolving Credit Facility along with the loan agreement with EPO were terminated.  Duncan Energy Partners' existing $282.3 million DEP Term Loan remains in place and is scheduled to mature in December 2011.

Duncan Energy Partners entered into the new $1.25 billion credit agreements primarily to provide its share of the funding requirements for the Haynesville Extension project under the Amended Acadian LLC Agreement (see Note 13).  Variable interest rates charged under the new credit facilities are based on LIBOR or a base rate, both as defined in the agreement.

***Covenants***

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2010.

***Information Regarding Variable Interest Rates Paid***

The following table shows the range of interest rates and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2010:

| | Range of Interest Rates Paid | Weighted-Average Interest Rate Paid |
|---|---|---|
| EPO Multi-Year Revolving Credit Facility | 0.73% to 3.25% | 0.84% |
| DEP Revolving Credit Facility | 0.80% to 1.19% | 0.94% |
| DEP Term Loan | 0.93% to 1.09% | 1.00% |
| Petal GO Zone Bonds | 0.12% to 0.30% | 0.24% |

***Consolidated Debt Maturity Table***

The following table presents contractually scheduled maturities of our consolidated debt obligations for the next five years, and in total thereafter:

| | | Scheduled Maturities of Debt | | | | |
|---|---|---|---|---|---|---|
| | Total | 2011 | 2012 | 2013 | 2014 | After 2014 |
| Revolving Credit Facilities | $ 282.5 | $ 247.5 | $ 35.0 | $ -- | $ -- | $ -- |
| Senior Notes | 10,500.0 | 450.0 | 1,000.0 | 1,200.0 | 1,150.0 | 6,700.0 |
| Term Loans | 282.3 | 282.3 | -- | -- | -- | -- |
| Junior Subordinated Notes | 1,532.7 | -- | -- | -- | -- | 1,532.7 |
| Other | 57.5 | -- | -- | -- | -- | 57.5 |
| Total | $ 12,655.0 | $ 979.8 | $ 1,035.0 | $ 1,200.0 | $ 1,150.0 | $ 8,290.2 |

Long-term and current maturities of debt reflect the classification of such obligations at September 30, 2010 after taking into consideration EPO's ability to use available long-term borrowing capacity under its Multi-Year Revolving Credit Facility to satisfy the current maturities of Senior Notes B ($450.0 million due in February 2011) and the refinancing by Duncan Energy Partners in October 2010 of its existing revolving credit facility on a long-term basis.

***Debt Obligations of Unconsolidated Affiliates***

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2010, (ii) the total debt of each unconsolidated affiliate at September 30, 2010 (on a 100% basis to the unconsolidated affiliate) and (iii) the corresponding scheduled maturities of such debt.

| | | | Scheduled Maturities of Debt | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Ownership Interest | Total | Remainder of 2010 | 2011 | 2012 | 2013 | 2014 | After 2014 |
| Poseidon | 36% | $ 92.0 | $ -- | $ 92.0 | $ -- | $ -- | $ -- | $ -- |
| Evangeline | 49.5% | 6.4 | 3.2 | 3.2 | -- | -- | -- | -- |
| Centennial | 50% | 113.2 | 2.3 | 9.0 | 8.9 | 8.6 | 8.6 | 75.8 |
| Total | | $ 211.6 | $ 5.5 | $ 104.2 | $ 8.9 | $ 8.6 | $ 8.6 | $ 75.8 |

The credit agreements of these unconsolidated affiliates include customary covenants, including financial covenants. These businesses were in compliance with such financial covenants at September 30, 2010. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution is scheduled to be paid.

There have been no significant changes in the terms of the debt obligations of our unconsolidated affiliates since those reported in our 2009 Form 10-K.

**Note 11.  Equity and Distributions**

Our common units represent limited partner interests, which give 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 the Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the GAAP-based equity amounts presented in our consolidated financial statements.  Earnings and cash distributions are allocated to holders of our common units in accordance with their respective ownership interests.

***Registration Statements and Equity Offerings***

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate of 70,000,000 common units in connection with our distribution reinvestment plan ("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 39,980,148 common units have been issued under the DRIP through September 30, 2010.

In addition to the DRIP, we have filed a registration statement with the SEC authorizing the issuance of up to an aggregate of 1,200,000 common units in connection with our employee unit purchase plan ("EUPP").  Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions.  A total of 972,768 common units have been issued to employees under this plan through September 30, 2010.

In July 2010, we filed a new universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities.  No securities have been issued under this registration statement as of the filing date of this quarterly report.  Under our prior universal shelf registration statement we issued 43,652,500 common units, which generated $1.27 billion of net cash proceeds, and $5.2 billion of senior notes.

The following table reflects the number of common units issued and the net cash proceeds received from underwritten offerings and the DRIP and EUPP during the nine months ended September 30, 2010:

| | | Net Cash Proceeds from Issuance of Common Units | | |
|---|---|---|---|---|
| | Number of Common Units Issued | Contributed by Limited Partners | Contributed by General Partner | Total Net Cash Proceeds |
| January underwritten offering | 10,925,000 | $ 343.3 | $ 7.0 | $ 350.3 |
| February DRIP and EUPP | 2,834,584 | 85.0 | 1.8 | 86.8 |
| April underwritten offering | 13,800,000 | 474.9 | 9.7 | 484.6 |
| May DRIP and EUPP | 2,039,670 | 67.1 | 1.3 | 68.4 |
| August DRIP and EUPP | 1,866,398 | 66.4 | 1.5 | 67.9 |
| Total 2010 | 31,465,652 | $ 1,036.7 | $ 21.3 | $ 1,058.0 |

In January 2010, we issued 10,925,000 common units (including an over-allotment of 1,425,000 common units) to the public at an offering price of $32.42 per unit.  We used the total net cash proceeds of $350.3 million to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In April 2010, we issued 13,800,000 common units (including an over-allotment of 1,800,000 common units) to the public at an offering price of $35.55 per unit. We used the total net cash proceeds of $484.6 million to fund a portion of the cash consideration paid to acquire the State Line and Fairplay systems in May 2010 (see Note 8) and for general partnership purposes.

In September 2010, we issued 523,306 common units to EPCO in exchange for its equity interests in Enterprise Transportation Company ("ETC"), which provides tank truck service for customers in the energy industry. Since we and EPCO are under common control, we recorded the net assets of ETC based on EPCO's historical basis of $30.6 million. The equity consideration we issued was based on the average closing price of our common units over a 20-day period ending September 28, 2010.

Net cash proceeds received in 2010 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.

***Class B Units***

In October 2009, in connection with the TEPPCO Merger, a privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.< /font>

***Summary of Changes in Outstanding Units***

The following table summarizes changes in the number of our limited partner units outstanding since December 31, 2009:

| | Common Units | Restricted Common Units | Class B Units | Treasury Units |
|---|---|---|---|---|
| **Balance, December 31, 2009** | 603,202,828 | 2,720,882 | 4,520,431 | -- |
| Common units issued in connection with underwritten offerings | 24,725,000 | -- | -- | -- |
| Common units issued in connection with DRIP and EUPP | 6,740,652 | -- | -- | -- |
| Common units issued to EPCO in exchange for equity interest in trucking business | 523,306 | -- | -- | -- |
| Common units issued in connection with equity awards | 178,474 | -- | -- | -- |
| Restricted units issued | -- | 1,353,425 | -- | -- |
| Forfeiture of restricted units | -- | (103,558) | -- | -- |
| Conversion of restricted units to common units | 339,628 | (339,628) | -- | -- |
| Acquisition of treasury units | (88,623) | -- | -- | 88,623 |
| Cancellation of treasury units | -- | -- | -- | (88,623) |
| Other | (61) | -- | -- | -- |
| **Balance, September 30, 2010** | 635,621,204 | 3,631,121 | 4,520,431 | -- |

***Summary of Changes in Limited Partners' Equity***

The following table details changes in limited partners' equity since December 31, 2009:

| | Common Units | Restricted Common Units | Class B Units | Total |
|---|---|---|---|---|
| **Balance, December 31, 2009** | $ 9,173.5 | $ 37.7 | $ 118.5 | $ 9,329.7 |
| Net income | 913.6 | 5.1 | -- | 918.7 |
| Operating lease expenses paid by EPCO | 0.5 | -- | -- | 0.5 |
| Cash distributions paid to partners | (1,066.0) | (5.8) | -- | (1,071.8) |
| Unit option-related reimbursements to EPCO | (9.7) | -- | -- | (9.7) |
| Common units issued to EPCO in exchange for equity interest in trucking business | 30.6 | -- | -- | 30.6 |
| Net cash proceeds from issuance of common units | 1,036.7 | -- | -- | 1,036.7 |
| Cash proceeds from exercise of unit options | 6.6 | -- | -- | 6.6 |
| Amortization of equity awards | 20.4 | 25.1 | -- | 45.5 |
| Acquisition of treasury units | -- | (3.0) | -- | (3.0) |
| Other | -- | 0.2 | -- | 0.2 |
| **Balance, September 30, 2010** | $ 10,106.2 | $ 59.3 | $ 118.5 | $ 10,284.0 |

***Distributions to Partners***

The following table presents our declared quarterly cash distribution rates per common unit since the first quarter of 2009 and the related record and distribution payment dates. The quarterly cash distribution rates per common unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

| | Distribution Per Common Unit | Record Date | Payment Date |
|---|---|---|---|
| **2009** | | | |
| 1st Quarter | $0.5375 | Apr. 30, 2009 | May 8, 2009 |
| 2nd Quarter | $0.5450 | Jul. 31, 2009 | Aug. 7, 2009 |
| 3rd Quarter | $0.5525 | Oct. 30, 2009 | Nov. 5, 2009 |
| 4th Quarter | $0.5600 | Jan. 29, 2010 | Feb. 4, 2010 |
| **2010** | | | |
| 1st Quarter | $0.5675 | Apr. 30, 2010 | May 6, 2010 |
| 2nd Quarter | $0.5750 | Jul. 30, 2010 | Aug. 5, 2010 |
| 3rd Quarter | $0.5825 | Oct. 29, 2010 | Nov. 8, 2010 |

The following table presents our total cash distributions paid to partners for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Standard distributions to EPGP | $ 7.4 | $ 5.1 | $ 21.8 | $ 15.0 |
| Incentive distributions to EPGP | 58.7 | 38.1 | 169.5 | 109.9 |
| Limited partner distributions | 366.1 | 250.8 | 1,071.8 | 735.2 |
| Cash distributions paid to partners | $ 432.2 | $ 294.0 | $ 1,263.1 | $ 860.1 |

***Accumulated Other Comprehensive Income (Loss)***

Our accumulated other comprehensive income (loss) amounts primarily include the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Amounts accumulated in other comprehensive income (loss) related to cash flow hedges are reclassified into earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

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**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

The following table presents the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| Commodity derivative instruments (1) | $ (41.1) | $ 0.5 |
| Interest rate derivative instruments (1) | (144.7) | (12.5) |
| Foreign currency derivative instruments (1) | -- | 0.4 |
| Foreign currency translation adjustment (2) | 1.1 | 0.8 |
| Pension and postretirement benefit plans | (1.7) | (0.8) |
| Subtotal | (186.4) | (11.6) |
| Amounts attributable to noncontrolling interests | 1.0 | 3.2 |
| Total accumulated other comprehensive loss in partners' equity | $ (185.4) | $ (8.4) |

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.

***Noncontrolling Interests***

Prior to the completion of the TEPPCO Merger, we accounted for the economic interest of the former owners of TEPPCO and TEPPCO GP within noncontrolling interests. Under this method of presentation, all pre-merger revenues and expenses of TEPPCO and TEPPCO GP are included in net income, and the former owners' share of the income of TEPPCO and TEPPCO GP is allocated to net income attributable to noncontrolling interest.

The following table presents the components of noncontrolling interest as presented on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| Limited partners of Duncan Energy Partners: | | |
| Third-party owners of Duncan Energy Partners (1) | $ 410.3 | $ 414.3 |
| Related party owners of Duncan Energy Partners | 1.7 | 1.7 |
| Joint venture partners (2) | 116.5 | 117.4 |
| Accumulated other comprehensive loss attributable to noncontrolling interests | (1.0) | (3.2) |
| Total | $ 527.5 | $ 530.2 |

(1) Represents non-affiliate public unitholders of Duncan Energy Partners.
(2) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole Pipeline Company, Tri-States Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline, LLC and Wilprise Pipeline Company LLC.

The following table presents the components of net income (loss) attributable to noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Former owners of TEPPCO (1) | $ -- | $ (42.1) | $ -- | $ 48.5 |
| Limited partners of Duncan Energy Partners | 8.5 | 10.1 | 26.8 | 21.8 |
| Joint venture partners | 5.5 | 6.9 | 19.3 | 20.7 |
| Total | $ 14.0 | $ (25.1) | $ 46.1 | $ 91.0 |

(1) TEPPCO recorded $51.0 million in charges during the three months ended September 30, 2009 primarily related to the indefinite suspension of certain river terminal projects (see Note 4).

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Cash Flows and Unaudited Condensed Statements of Consolidated Equity for the periods indicated:

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | **2010** | **2009** |
| Cash distributions paid to noncontrolling interests: | | |
| Limited partners of TEPPCO | $ -- | $ 274.5 |
| Limited partners of Duncan Energy Partners | 32.1 | 23.2 |
| Joint venture partners | 21.9 | 24.6 |
| Total cash distributions paid to noncontrolling interests | $ 54.0 | $ 322.3 |
| Cash contributions from noncontrolling interests: | | |
| Limited partners of TEPPCO | $ -- | $ 3.5 |
| Limited partners of Duncan Energy Partners | 1.2 | 137.4 |
| Joint venture partners | 1.6 | (2.2) |
| Total cash contributions from noncontrolling interests | $ 2.8 | $ 138.7 |

Cash distributions paid to the limited partners of Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger on October 26, 2009) represent the quarterly cash distributions paid by these entities to their unitholders. Cash contributions received from the limited partners of Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger) represent net cash proceeds each entity received from the issuance of limited partner units. In June and July 2009, Duncan Energy Partners issued 8,943,400 of its common units, which generated net cash proceeds of approximately $137.4 million. Duncan Energy Partners used the net proceeds from its issuance of these units to repurchase and cancel an equal number of its common units beneficially owned by EPO.

**Note 12. Business Segments**

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services and (v) Petrochemical & Refined Products 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 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.< /font>

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) operating lease expenses for which we do not have the payment obligation (e.g., the EPCO retained leases); (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 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 Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Revenues | $ 8,067.8 | $ 6,789.4 | $ 24,155.7 | $ 17,110.6 |
| Less: Operating costs and expenses | (7,460.1) | (6,395.8) | (22,406.2) | (15,796.9) |
| Add: Equity in income of unconsolidated affiliates | 17.5 | 15.0 | 50.2 | 32.0 |
| Depreciation, amortization and accretion in operating costs and expenses (1) | 235.1 | 206.0 | 674.5 | 602.9 |
| Non-cash asset impairment charges | -- | 24.0 | 1.5 | 26.3 |
| Operating lease expenses paid by EPCO | 0.2 | 0.2 | 0.5 | 0.5 |
| Gains from asset sales and related transactions in operating costs and expenses (2) | (39.7) | (0.1) | (45.3) | (0.5) |
| Total segment gross operating margin | $ 820.8 | $ 638.7 | $ 2,430.9 | $ 1,974.9 |

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.
(2) Amount is a component of "Gains from asset sales and related transactions" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents a reconciliation of our non-GAAP total segment gross operating margin to GAAP operating income and income before provision for income taxes for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Total segment gross operating margin | $ 820.8 | $ 638.7 | $ 2,430.9 | $ 1,974.9 |
| Adjustments to reconcile total segment gross operating margin to operating income: | | | | |
| Depreciation, amortization and accretion in operating costs and expenses | (235.1) | (206.0) | (674.5) | (602.9) |
| Non-cash asset impairment charges | -- | (24.0) | (1.5) | (26.3) |
| Operating lease expenses paid by EPCO | (0.2) | (0.2) | (0.5) | (0.5) |
| Gains from asset sales and related transactions in operating costs and expenses | 39.7 | 0.1 | 45.3 | 0.5 |
| General and administrative costs | (56.0) | (52.3) | (131.5) | (133.3) |
| Operating income | 569.2 | 356.3 | 1,668.2 | 1,212.4 |
| Other expense, net | (178.4) | (160.8) | (495.1) | (469.8) |
| Income before provision for income taxes | $ 390.8 | $ 195.5 | $ 1,173.1 | $ 742.6 |

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

| | Reportable Segments | | | | | | |
|---|---|---|---|---|---|---|---|
| | NGL Pipelines & Services | Onshore Natural Gas Pipelines & Services | Onshore Crude Oil Pipelines & Services | Offshore Pipelines & Services | Petrochemical & Refined Products Services | Adjustments And Eliminations | Consolidated Totals |
| **Revenues from third parties:** | | | | | | | |
| Three months ended September 30, 2010 | $ 3,169.3 | $ 781.8 | $ 2,726.0 | $ 68.3 | $ 1,188.7 | $ -- | $ 7,934.1 |
| Three months ended September 30, 2009 | 3,141.7 | 708.1 | 2,007.0 | 101.7 | 720.5 | -- | 6,679.0 |
| Nine months ended September 30, 2010 | 9,759.4 | 2,679.1 | 7,742.0 | 240.3 | 3,252.8 | -- | 23,673.6 |
| Nine months ended September 30, 2009 | 7,767.6 | 2,007.6 | 5,003.1 | 247.5 | 1,662.6 | -- | 16,688.4 |
| **Revenues from related parties:** | | | | | | | |
| Three months ended September 30, 2010 | 65.2 | 66.1 | (0.1) | 2.5 | -- | -- | 133.7 |
| Three months ended September 30, 2009 | 47.2 | 60.2 | 3.0 | -- | -- | -- | 110.4 |
| Nine months ended September 30, 2010 | 300.7 | 175.2 | (0.2) | 6.4 | -- | -- | 482.1 |
| Nine months ended September 30, 2009 | 245.3 | 173.1 | 3.8 | -- | -- | -- | 422.2 |
| **Intersegment and intrasegment revenues:** | | | | | | | |
| Three months ended September 30, 2010 | 2,378.1 | 261.0 | 313.4 | 0.5 | 309.7 | (3,262.7) | -- |
| Three months ended September 30, 2009 | 1,640.5 | 125.5 | 11.1 | 0.4 | 158.6 | (1,936.1) | -- |
| Nine months ended September 30, 2010 | 7,333.0 | 689.3 | 561.5 | 1.2 | 854.7 | (9,439.7) | -- |
| Nine months ended September 30, 2009 | 4,535.5 | 392.8 | 34.7 | 1.0 | 393.8 | (5,357.8) | -- |
| **Total revenues:** | | | | | | | |
| Three months ended September 30, 2010 | 5,612.6 | 1,108.9 | 3,039.3 | 71.3 | 1,498.4 | (3,262.7) | 8,067.8 |
| Three months ended September 30, 2009 | 4,829.4 | 893.8 | 2,021.1 | 102.1 | 879.1 | (1,936.1) | 6,789.4 |
| Nine months ended September 30, 2010 | 17,393.1 | 3,543.6 | 8,303.3 | 247.9 | 4,107.5 | (9,439.7) | 24,155.7 |
| Nine months ended September 30, 2009 | 12,548.4 | 2,573.5 | 5,041.6 | 248.5 | 2,056.4 | (5,357.8) | 17,110.6 |
| **Equity in income (loss) of unconsolidated affiliates:** | | | | | | | |
| Three months ended September 30, 2010 | 5.1 | 1.2 | 1.6 | 10.1 | (0.5) | -- | 17.5 |
| Three months ended September 30, 2009 | 4.0 | 1.4 | 1.2 | 10.6 | (2.2) | -- | 15.0 |
| Nine months ended September 30, 2010 | 12.1 | 3.4 | 7.5 | 33.0 | (5.8) | -- | 50.2 |
| Nine months ended September 30, 2009 | 7.5 | 3.9 | 7.4 | 22.1 | (8.9) | -- | 32.0 |
| **Gross operating margin:** | | | | | | | |
| Three months ended September 30, 2010 | 397.2 | 154.1 | 35.0 | 68.3 | 166.2 | -- | 820.8 |
| Three months ended September 30, 2009 | 403.4 | 108.4 | 34.1 | 22.8 | 70.0 | -- | 638.7 |
| Nine months ended September 30, 2010 | 1,275.5 | 391.3 | 87.6 | 232.2 | 444.3 | -- | 2,430.9 |
| Nine months ended September 30, 2009 | 1,118.1 | 391.5 | 126.7 | 83.0 | 255.6 | -- | 1,974.9 |
| **Segment assets:** | | | | | | | |
| At September 30, 2010 | 7,388.7 | 8,147.0 | 899.5 | 2,033.3 | 3,651.5 | 1,467.7 | 23,587.7 |
| At December 31, 2009 | 7,191.2 | 6,918.7 | 865.4 | 2,121.4 | 3,359.0 | 1,207.2 | 21,662.9 |
| **Property, plant and equipment:** (see Note 6) | | | | | | | |
| At September 30, 2010 | 6,525.1 | 6,536.9 | 407.4 | 1,414.0 | 2,458.9 | 1,467.7 | 18,810.0 |
| At December 31, 2009 | 6,392.8 | 6,074.6 | 377.4 | 1,480.9 | 2,156.3 | 1,207.2 | 17,689.2 |
| **Investments in unconsolidated affiliates:** (see Note 7) | | | | | | | |
| At September 30, 2010 | 132.7 | 32.6 | 174.7 | 445.4 | 79.3 | -- | 864.7 |
| At December 31, 2009 | 141.6 | 32.0 | 178.5 | 456.9 | 81.6 | -- | 890.6 |
| **Intangible assets, net:** (see Note 9) | | | | | | | |
| At September 30, 2010 | 389.7 | 1,266.4 | 6.2 | 91.8 | 106.2 | -- | 1,860.3 |
| At December 31, 2009 | 315.6 | 527.2 | 6.5 | 101.5 | 114.0 | -- | 1,064.8 |
| **Goodwill:** (see Note 9) | | | | | | | |
| At September 30, 2010 | 341.2 | 311.1 | 311.2 | 82.1 | 1,007.1 | -- | 2,052.7 |
| At December 31, 2009 | 341.2 | 284.9 | 303.0 | 82.1 | 1,007.1 | -- | 2,018.3 |

Property, plant and equipment, intangible assets and goodwill for the Onshore Natural Gas Pipelines & Services business segment and intangible assets for the NGL Pipelines & Services business segment increased in May 2010 as a result of completing the State Line and Fairplay acquisitions (see Note 8).

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The following table provides additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **NGL Pipelines & Services:** | | | | |
| Sales of NGLs | $ 3,048.0 | $ 3,015.4 | $ 9,516.5 | $ 7,527.6 |
| Sales of other petroleum and related products | 0.6 | 0.6 | 1.8 | 1.5 |
| Midstream services | 185.9 | 172.9 | 541.8 | 483.8 |
| Total | 3,234.5 | 3,188.9 | 10,060.1 | 8,012.9 |
| **Onshore Natural Gas Pipelines & Services:** | | | | |
| Sales of natural gas | 651.0 | 585.8 | 2,281.8 | 1,639.5 |
| Midstream services | 196.9 | 182.5 | 572.5 | 541.2 |
| Total | 847.9 | 768.3 | 2,854.3 | 2,180.7 |
| **Onshore Crude Oil Pipelines & Services:** | | | | |
| Sales of crude oil | 2,701.4 | 1,991.3 | 7,672.1 | 4,946.1 |
| Midstream services | 24.5 | 18.7 | 69.7 | 60.8 |
| Total | 2,725.9 | 2,010.0 | 7,741.8 | 5,006.9 |
| **Offshore Pipelines & Services:** | | | | |
| Sales of natural gas | 0.2 | 0.3 | 1.0 | 0.9 |
| Sales of crude oil | 2.3 | 2.0 | 6.3 | 3.1 |
| Midstream services | 68.3 | 99.4 | 239.4 | 243.5 |
| Total | 70.8 | 101.7 | 246.7 | 247.5 |
| **Petrochemical & Refined Products Services:** | | | | |
| Sales of other petroleum and related products | 1,056.3 | 597.2 | 2,860.6 | 1,272.0 |
| Midstream services | 132.4 | 123.3 | 392.2 | 390.6 |
| Total | 1,188.7 | 720.5 | 3,252.8 | 1,662.6 |
| **Total consolidated revenues** | $ 8,067.8 | $ 6,789.4 | $ 24,155.7 | $ 17,110.6 |
| | | | | |
| **Consolidated cost and expenses:** | | | | |
| Operating costs and expenses: | | | | |
| Cost of sales related to our marketing activities | $ 6,234.5 | $ 5,026.6 | $ 18,577.2 | $ 12,302.5 |
| Depreciation, amortization and accretion | 235.1 | 206.0 | 674.5 | 602.9 |
| Gains from asset sales and related transactions | (39.7) | (0.1) | (45.3) | (0.5) |
| Non-cash asset impairment charges | -- | 24.0 | 1.5 | 26.3 |
| Other operating costs and expenses | 1,030.2 | 1,139.3 | 3,198.3 | 2,865.7 |
| General and administrative costs | 56.0 | 52.3 | 131.5 | 133.3 |
| **Total consolidated costs and expenses** | $ 7,516.1 | $ 6,448.1 | $ 22,537.7 | $ 15,930.2 |

**Note 13. Related Party Transactions**

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

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Revenues – related parties:** | | | | |
| Energy Transfer Equity and subsidiaries | $ 66.2 | $ 54.5 | $ 312.7 | $ 266.5 |
| Unconsolidated affiliates | 67.5 | 55.9 | 169.4 | 155.7 |
| Total revenue – related parties | $ 133.7 | $ 110.4 | $ 482.1 | $ 422.2 |
| **Costs and expenses – related parties:** | | | | |
| EPCO and affiliates | $ 198.8 | $ 164.3 | $ 521.9 | $ 459.5 |
| Energy Transfer Equity and subsidiaries | 172.6 | 113.1 | 496.7 | 310.1 |
| Unconsolidated affiliates | 10.4 | 9.1 | 32.1 | 22.8 |
| Other | -- | 6.5 | -- | 35.1 |
| Total costs and expenses – related parties | $ 381.8 | $ 293.0 | $ 1,050.7 | $ 827.5 |

The following table summarizes our related party receivable and payable amounts at the dates indicated:

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| **Accounts receivable - related parties:** | | |
| Energy Transfer Equity and subsidiaries | $ 9.3 | $ 28.2 |
| Other | 21.7 | 10.2 |
| Total accounts receivable – related parties | $ 31.0 | $ 38.4 |
| | | |
| **Accounts payable - related parties:** | | |
| EPCO and affiliates | $ 49.8 | $ 26.8 |
| Energy Transfer Equity and subsidiaries | 39.3 | 33.4 |
| Other | 9.1 | 9.6 |
| Total accounts payable – related parties | $ 98.2 | $ 69.8 |

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

***Relationship with EPCO and Affiliates***

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

§ EPCO and its privately held affiliates;

§ EPGP, our sole general partner; and

§ Holdings, which owns and controls our general partner.

EPCO is a privately held company controlled collectively by the EPCO Trustees. At September 30, 2010, EPCO and its affiliates (including Dan Duncan LLC and two Duncan family trusts the beneficiaries of which include the estate of Mr. Duncan) beneficially owned interests in the following entities:

| | Number of Units | Percentage of Outstanding Units |
|---|---|---|
| Enterprise Products Partners L.P. (1,2) | 198,630,738 | 30.9% |
| Enterprise GP Holdings L.P. (3) | 106,648,357 | 76.6% |

(1) Includes 4,520,431 Class B units owned by a privately held affiliate of EPCO, 21,563,177 common units owned by Holdings, and 523,306 common units issued to EPCO in September 2010.
(2) Holdings owns 100% of our general partner, EPGP.
(3) Dan Duncan LLC owns 100% of the member interests of EPE Holdings, which is the general partner of Holdings.

The principal business activity of EPGP is to act as our sole managing partner. The executive officers and certain of the directors of EPGP are employees of EPCO. The following table presents cash distributions paid by us to EPGP for the periods indicated:

| | For the Nine Months Ended September 30, 2010 | 2009 |
|---|---|---|
| General partner distributions | $ 21.8 | $ 15.0 |
| Incentive distributions | 169.5 | 109.9 |
| Total distributions | $ 191.3 | $ 124.9 |

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Holdings and their respective other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us, Holdings and other investments to fund their other operations and to meet their debt obligations. The following table presents cash distributions received by EPCO and its privately held affiliates from us and Holdings for the periods indicated:

| | For the Nine Months Ended September 30, 2010 | 2009 |
|---|---|---|
| Enterprise Products Partners | $ 255.1 | $ 232.6 |
| Holdings | 176.6 | 149.6 |
| Total distributions | $ 431.7 | $ 382.2 |

Substantially all of the ownership interests in us that are owned or controlled by 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 Holdings, Dan Duncan LLC and certain trusts of which the estate of Mr. Duncan is a beneficiary, are pledged as security under the credit facility of a privately held affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Holdings and us.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

*EPCO ASA*. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. We, Duncan Energy Partners, Holdings 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 with respect to 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. See Note 16 for additional information regarding our insurance programs.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment it holds pursuant to operating leases and has assigned to us its purchase option under such leases. EPCO remains liable for the actual cash payments associated with these lease 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.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each e ntity's business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Operating costs and expenses | $ 159.4 | $ 139.4 | $ 434.7 | $ 384.6 |
| General and administrative expenses | 39.4 | 24.9 | 87.2 | 74.9 |
| Total costs and expenses | $ 198.8 | $ 164.3 | $ 521.9 | $ 459.5 |

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

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities (as defined within the ASA) with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Holdings, Duncan Energy Partners and their respective general partners.

*Acquisition of EPCO's Trucking Business*. Historically, EPCO has provided us with tank truck services for the transportation of NGLs and other products. In September 2010, we acquired EPCO's ownership interests in its trucking business, or ETC, in exchange for 523,306 of our common units. Since we and EPCO are under common control, we recorded the net assets of ETC based on EPCO's historical basis of $30.6 million. The equity consideration we issued was based on the average closing price of our common units over a 20-day period ending September 28, 2010.

***Relationship with Energy Transfer Equity***

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 sales contract with Titan Energy Partners, L.P. ("Titan"), which is a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract, which was scheduled to expire March 31, 2010, has been extended through March 31, 2015. In addition, 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.

***Relationships with Unconsolidated Affiliates***

Many of our unconsolidated affiliates (see Note 7) support or complement our other midstream business operations. The following information summarizes significant related party transactions with our 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 $58.9 million and $49.8 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, revenues from Evangeline were $145.7 million and $143.3 million, respectively.

§ We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $3.7 million and $2.6 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, revenues from Promix were $9.9 million and $7.7 million, respectively. Expenses with Promix were $9.7 million and $7.7 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, expenses with Promix were $25.8 million and $18.7 million, respectively.

§ We paid $0.2 million and $1.1 million to Centennial for pipeline transportation services during the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, we paid Centennial $3.1 million and $3.5 million, respectively, for such services.

§ We paid $0.8 million and $1.4 million to Seaway for pipeline transportation and tank rentals during the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, we paid Seaway $3.5 million and $4.0 million, respectively, for such services.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $2.9 million and $2.7 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, we charged affiliates $8.6 million and $8.0 million, respectively.

***Relationship with Duncan Energy Partners***

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 of EPCO under common control. Duncan Energy Partners is engaged in the business of: (i) NGL transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas. We formed Duncan Energy Partners in September 2006, but it did not own or acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of common units and acquired controlling interests in five midstream energy businesses from EPO in a drop down transaction. On December 8, 2008, Duncan Energy Partners acquired controlling interests in three additional midstream energy businesses from EPO through a second drop down transaction.

At September 30, 2010, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At September 30, 2010, EPO owned 58.5% of Duncan Energy Partners' limited partner interests and 100% of its general partner. Due to our control of Duncan Energy Partners, its financial statements are consolidated with those of our own and our transactions with Duncan Energy Partners are eliminated in consolidation.

In June 2010, EPO entered into the Amended Acadian LLC Agreement with Duncan Energy Partners. This document includes the agreement between Duncan Energy Partners and EPO regarding funding arrangements for the Haynesville Extension project. This expansion capital project will extend our south Louisiana intrastate natural gas pipeline system, which is owned by Acadian Gas, LLC, into northwest Louisiana and the Haynesville Shale production area. Duncan Energy Partners will fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures. The total expected cost of the Haynesville Extension project is approximately $1.56 billion (including capitalized interest), with Duncan Energy Partners' share currently estimated at $1.03 billion. I n order to address its funding requirements under the Haynesville Extension project, Duncan Energy Partners entered into new senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010 (see Note 10).

In June 2010, Duncan Energy Partners entered into a $200 million revolving loan agreement with EPO. Duncan Energy Partners' borrowings under this revolving loan agreement were primarily used to fund its 66% share of the cash calls to fund this capital project. At September 30, 2010, the amount borrowed under this intercompany loan agreement was $125.0 million. This loan agreement was terminated on October 25, 2010 and amounts due thereunder were repaid using borrowings under Duncan Energy Partners' new $1.25 billion credit facilities. Since Duncan Energy Partners is a consolidated subsidiary of ours, all amounts related to the EPO loan (e.g., principal amounts borrowed/loaned, interest expense/revenue, etc.) were eliminated in the preparation of our consolidated financial stateme nts.

**Note 14. 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 Class B 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, the Class B 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 price 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 our calculation of the net income available to EPGP for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Net income attributable to Enterprise Products Partners L.P. | $ 371.9 | $ 212.9 | $ 1,106.9 | $ 624.8 |
| Less incentive earnings allocations to EPGP | (58.7) | (38.1) | (169.5) | (109.9) |
| Net income available after incentive earnings allocation | 313.2 | 174.8 | 937.4 | 514.9 |
| Multiplied by EPGP ownership interest | 2.0% | 2.0% | 2.0% | 2.0% |
| Standard earnings allocation to EPGP | $ 6.2 | $ 3.5 | $ 18.7 | $ 10.3 |
| | | | | |
| Incentive earnings allocation to EPGP | $ 58.7 | $ 38.1 | $ 169.5 | $ 109.9 |
| Standard earnings allocation to EPGP | 6.2 | 3.5 | 18.7 | 10.3 |
| Net income available to EPGP | 64.9 | 41.6 | 188.2 | 120.2 |
| Two-class method adjustment (1) | 1.6 | 2.5 | 6.3 | 5.3 |
| Net income available to EPGP for EPU purposes | $ 66.5 | $ 44.1 | $ 194.5 | $ 125.5 |

(1) FASB guidance specific to master limited partnerships has been applied for purposes of computing basic and diluted earnings per unit.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **BASIC EARNINGS PER UNIT** | | | | |
| **Numerator** | | | | |
| Net income attributable to Enterprise Products Partners L.P. | $ 371.9 | $ 212.9 | $ 1,106.9 | $ 624.8 |
| Net income available to EPGP for EPU purposes | (66.5) | (44.1) | (194.5) | (125.5) |
| Net income available to limited partners | $ 305.4 | $ 168.8 | $ 912.4 | $ 499.3 |
| **Denominator** | | | | |
| Weighted – average common units outstanding | 634.4 | 461.5 | 626.4 | 456.0 |
| Weighted – average restricted common units outstanding | 3.6 | 2.8 | 3.5 | 2.4 |
| Total | 638.0 | 464.3 | 629.9 | 458.4 |
| **Basic earnings per unit** | | | | |
| Net income per unit before EPGP earnings allocation | $ 0.58 | $ 0.45 | $ 1.76 | $ 1.36 |
| Net income available to EPGP | (0.10) | (0.09) | (0.31) | (0.27) |
| Net income available to limited partners | $ 0.48 | $ 0.36 | $ 1.45 | $ 1.09 |
| **DILUTED EARNINGS PER UNIT** | | | | |
| **Numerator** | | | | |
| Net income attributable to Enterprise Products Partners L.P. | $ 371.9 | $ 212.9 | $ 1,106.9 | $ 624.8 |
| Net income available to EPGP for EPU purposes | (66.5) | (44.1) | (194.5) | (125.5) |
| Net income available to limited partners | $ 305.4 | $ 168.8 | $ 912.4 | $ 499.3 |
| **Denominator** | | | | |
| Weighted – average common units outstanding | 634.4 | 461.5 | 626.4 | 456.0 |
| Weighted – average restricted common units outstanding | 3.6 | 2.8 | 3.5 | 2.4 |
| Class B units outstanding | 4.5 | -- | 4.5 | -- |
| Incremental option units | 1.2 | 0.1 | 1.0 | 0.1 |
| Total | 643.7 | 464.4 | 635.4 | 458.5 |
| **Diluted earnings per unit** | | | | |
| Net income per unit before EPGP earnings allocation | $ 0.57 | $ 0.45 | $ 1.75 | $ 1.36 |
| Net income available to EPGP | (0.10) | (0.09) | (0.31) | (0.27) |
| Net income available to limited partners | $ 0.47 | $ 0.36 | $ 1.44 | $ 1.09 |

## Note 15. Commitments and Contingencies

***Litigation***

As part of our normal business activities, we or our unconsolidated affiliates are named on occasion as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. See Note 16 for information regarding our insurance program. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our consolidated financial position, results of operations or cash flows.

We have not recorded any significant reserves for litigation matters. Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves substantial uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional reserves. In an effort to mitigate potential adverse consequences of litigation, we may settle legal proceedings out of court.

On September 9, 2010, Sanjay Israni, a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, captioned *Sanjay Israni v. EPE Holdings LLC, Enterprise GP Holdings L.P., Enterprise Products Company, Enterprise Products Partners L.P., Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the “Israni Complaint”). The Israni Complaint alleges, among other things, that we along with the named directors and EPCO have breached fiduciary duties in connection with the proposed Holdings Merger (see Note 1) and that Holdings aided and abetted in these alleged breaches of fiduciary duties.

On September 24, 2010, Richard Fouke, a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, captioned *Richard Fouke v. EPE Holdings LLC, Enterprise GP Holdings L.P., Enterprise Products Company, Enterprise Products Partners L.P., Enterprise Products GP, LLC, Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Fouke Complaint"). The Fouke Complaint alleges, among other things, that we, along with the named directors, EPE Holdings, EPGP and EPCO breached the implied contractual covenant of good faith and fair dealing in connection w ith the proposed Holdings Merger and that Holdings and the other defendants aided and abetted in the alleged breach.

Additionally, on September 28, 2010, Eugene Lonergan, Sr., a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, captioned *Eugene Lonergan, Sr. v. EPE Holdings LLC, Enterprise GP Holdings L.P., Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Lonergan Complaint"). The Lonergan Complaint alleges that the named directors and EPE Holdings breached the implied contractual covenant of good faith and fair dealing, including failin g to make adequate disclosures, in connection with the proposed Holdings Merger. On October 8, 2010, the Court of Chancery of the State of Delaware held a hearing on a motion by the plaintiff to expedite the proceedings. On October 11, 2010, the motion was denied.

Finally, on October 11, 2010, John Psomas, a purported unitholder of our common units, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of our unitholders, captioned *John Psomas v. Enterprise Products Partners L.P., Enterprise Products GP, LLC, Michael A. Creel, W. Randall Fowler, A. James Teague, Michael J. Knesek, E. William Barnett, Charles M. Rampacek and Rex C. Ross* (the "Psomas Complaint"). The Psomas Complaint alleges that we and our general partner breached our partnership agreement by failing to submit the Holdings Merger Agreement to a vote of our unitholders and that the named directors breached their fiduciary duties of candor and full disclosure.

Each of the Israni, Fouke, Lonergan and Psomas Complaints seeks to enjoin the proposed merger transaction and, in the event the merger is consummated, the Psomas Complaint seeks a vote of our unitholders to ratify approval of the Holdings Merger and damages resulting from the named directors' alleged breaches of fiduciary duties. We cannot predict the outcome of these or any other lawsuits nor the amount of time and expense that will be required to resolve these or any other lawsuits filed in connection with the proposed Holdings Merger. We intend to vigorously defend against these lawsuits and any similar actions.

In October 2009, we received notice that the Colorado Department of Public Health and Environment, through its Air Pollution Control Division, had proposed a Compliance Order on Consent with Enterprise Gas Processing, L.L.C for alleged violations of the Colorado Air Pollution and Prevention and Control Act ("Colorado Act") with respect to operations at our Meeker natural gas processing facility. Under the Compliance Order, we paid an administrative fine of approximately $0.8 million in September 2010 and are required to operate the Meeker facility in compliance with the Colorado Act.

In December 2008, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. ("Marathon") as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State of New Mexico alleges violations of its air laws. Marathon agreed to a Consent Decree with the State of New Mexico, which was then approved by the District Court on December 21, 2009. Under the Consent Decree, Marathon paid the State of New Mexico approximately $0.6 million, agreed to $4.5 million of additional environmental projects i n New Mexico and agreed to two projects for "corrective measures" at the facility. We are in discussions with Marathon regarding the responsibility for these payments. We believe that any potential payment we make will not have a material impact on our consolidated financial position, results of operations or cash flows.

On March 29, 2007, a third party struck the West Red Line of our Mid-America Pipeline ("MAPL") releasing 1,725 barrels of natural gasoline. MAPL and EPO received letters dated June 4, 2009, from the U.S. Department of Justice ("DOJ") informing them that the DOJ desired to discuss violations of the federal Clean Water Act related to the release and potential settlement of the alleged violations. We have begun discussions with the DOJ and believe that the eventual resolution of this matter will result in a civil penalty exceeding $0.1 million. While our discussions with the DOJ are still at a preliminary stage, we believe that any potential payment we make in connection with this release will not have a material impact on our consolidated financial position, results of operations or cash flows.

***Regulatory Matters***

Certain scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide (which is a component of, and a product of combustion of, natural gas) and methane (which is a component of natural gas), may be contributing to global climate change and ocean acidification. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA") which, if it were to become law, would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases by the United States and would require most significant domestic sources of greenhouse gas emissions to obtain greenhouse gas emiss ion "allowances" corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun consideration of various legislative proposals for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency ("EPA") announced its finding that emissions of greenhouse gases from motor vehicles caused or contributed to climate change and presented an endangerment to human health and the environment. These findings by the EPA were the basis for motor vehicle greenhouse gas emissions standards promulgated on May 7, 2010, and may allow the agency to proceed with the adoption and implementation of additional regulations that would require permits or control emissions of greenhouse gases from industrial sources under existing provisions of the federal Clean Air Act. On May 13, 2010, the EPA issued a final rule setting forth a timetable for its Tit le V and Prevention of Significant Deterioration regulatory program, applicable in certain circumstances to new and modified industrial source of air emissions, to include consideration of greenhouse gas emissions. The EPA has also received petitions requesting that the agency further expand regulation of greenhouse gas emissions from industrial sources, which, over time, may lead to additional requirements. On April 12, 2010, the EPA proposed new rules that would require the mandatory reporting of greenhouse gas emissions by operators of natural gas compression, processing and storage facilities. These rules supplement disclosures and reporting required by the EPA in its October 30, 2009 mandatory greenhouse gas reporting rule. These and any new laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases, or that establish new reporting requirements, will require us to incur increased operating costs, and may have an adverse effect on our financial position, results of operations and cash flows.

***Contractual Obligations***

*Scheduled Maturities of Long-Term Debt*. With the exception of (i) routine fluctuations in the balance of our consolidated revolving credit facilities, (ii) the issuance of Senior Notes X, Y and Z in May 2010 and (iii) the repayments of the Pascagoula MBFC Loan in March 2010 and Senior Notes K in June 2010, there have been no significant changes in our consolidated debt obligations since those reported in our 2009 Form 10-K. See Note 10 for additional information regarding our consolidated debt obligations.

*Operating Lease Obligations*. Lease and rental expense included in costs and expenses was $18.3 million and $16.2 million during the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, lease and rental expense was $50.6 million and $45.0 million, respectively. There have been no material changes in our operating lease commitments since those reported in our 2009 Form 10-K.

*Purchase Obligations*. There have been no material changes in our consolidated purchase obligations since those reported in our 2009 Form 10-K.

During the three months ended September 30, 2009, TEPPCO determined that its river terminal business would not be able to meet certain volume commitments to a third party. As a result, TEPPCO recognized a $28.7 million charge for pipeline throughput deficiency fees it owed under the contract. The accrued deficiency charges are included in operating costs and expenses for the three and nine months ended September 30, 2009. There was no impact on net income attributable to Enterprise Products Partners, as all of this charge was absorbed by noncontrolling interests in consolidation (i.e., the former owners of TEPPCO). The balance of this accrued liability was $21.6 million at September 30, 2010.

***Other Claims***

As part of our normal business activities with joint venture partners, customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or other communications. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. However, in our opinion, the likelihood of a material adverse outcome to us resulting from such disputes is remote. Accordingly, we have not recorded any accruals for loss contingencies related to these matters. As of September 30, 2010, such claims against us totaled approximately $19.5 million.

***Centennial Guarantees***

We have certain guarantee obligations in connection with our ownership interest in Centennial, which owns a refined products pipeline system that extends from the Texas Gulf Coast to central Illinois. We guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of $56.6 million in the event of a default by Centennial. As of September 30, 2010, we have a recorded liability of $7.9 million representing the estimated fair value of our share of the Centennial debt guaranty.

In lieu of Centennial procuring insurance to satisfy third-party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million (in proportion to our 50% ownership interest in Centennial) in the event of a catastrophic event. At September 30, 2010, we have a recorded liability of $3.4 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

## Note 16. Significant Risks and Uncertainties

***Insurance-Related Risks***

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

EPCO completed its annual insurance renewal process during the second quarter of 2010, which resulted in an increase in premiums. EPCO's deductible for onshore physical damage from windstorms increased from $25.0 million per storm to $30.0 million per storm. EPCO's onshore insurance program currently provides $141.3 million of coverage per occurrence for named windstorm events compared to $150.0 million per occurrence in the prior year. With respect to offshore assets, the deductible for windstorm damage remained at $75.0 million per storm. EPCO's insurance program for offshore Gulf ofMexico assets currently provides $124.5 million of coverage in the aggregate compared to $100.0 million of coverage in the aggregate for the prior year. In addition, at EPCO's election, we now have access to an additional $17.5 million of coverage for either onshore or offshore windstorm-related damage claims. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence.

For certain of our offshore assets, producers continue to provide a specified level of physical damage insurance coverage for named windstorms. The producers associated with our Independence Hub and Marco Polo offshore Gulf of Mexico platforms continue to cover windstorm generated physical damage costs up to $300.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets. We do not have any business interruption coverage for offshore Gulf of Mexico assets when the outage is due to a windstorm. We have business interruption coverage for both onshore and offshore assets in connection with non-windstorm events. Assets covered by business interruption insurance must be out-of-service in excess of 60 days before any allowed losses from business interruption will be covered.

The following table summarizes cash proceeds we received from business interruption and property damage insurance claims during the periods indicated:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Business interruption proceeds:** | | | | |
| Hurricane Ike | $ -- | $ 19.2 | $ 1.1 | $ 19.2 |
| Total business interruption proceeds | -- | 19.2 | 1.1 | 19.2 |
| **Property damage proceeds:** | | | | |
| Hurricane Ivan | -- | 0.7 | -- | 0.7 |
| Hurricane Katrina | -- | 3.5 | -- | 26.7 |
| Hurricane Rita | -- | -- | 36.3 | -- |
| Hurricane Gustav | 57.8 | -- | 57.8 | -- |
| Hurricane Ike | 21.7 | -- | 23.6 | -- |
| Other | 28.0 | -- | 30.8 | -- |
| Total property damage proceeds | 107.5 | 4.2 | 148.5 | 27.4 |
| **Total** | $ 107.5 | $ 23.4 | $ 149.6 | $ 46.6 |

We recognized gains to the extent that we received cash proceeds from business interruption insurance claims. For the three and nine months ended September 30, 2009, we recognized $19.2 million of such gains, which are a component of operating income and gross operating margin for these periods. We recognized $1.1 million of gains from business interruption insurance proceeds during the nine months ended September 30, 2010.

Of the $107.5 million of property damage insurance proceeds we received during the three months ended September 30, 2010, $64.8 million is attributable to a segment of an offshore natural gas pipeline and certain components of an offshore platform that we elected to retire (dispose of) rather than repair. The $64.8 million of cash proceeds represents the negotiated insurance value of the covered assets and is a component of proceeds from asset sales and related transactions (investing activities) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows for the nine months ended September 30, 2010. Operating income for the three and nine months ended September 30, 2010 includes $56.6 million of net gains related to the disposition of these offshore assets. These net gains are a comp onent of gains from asset sales and related transactions (operating activities) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows and also part of operating costs and expenses as reported on our Unaudited Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2010, as applicable.

The remainder of property damage proceeds presented in the preceding table are attributable to insurance claims where the underlying assets were repaired. We recognize gains when the insurance proceeds we receive from property damage claims exceed the related repair costs. We received cash proceeds of $42.7 million and $83.7 million related to such claims during the three and nine months ended September 30, 2010, respectively. Cash proceeds from such claims were $4.2 million and $27.4 million during the three and nine months ended September 30, 2009, respectively. Operating income and gross operating margin for the three and nine months ended September 30, 2010 include $8.2 million and $26.4 million, respecti vely, of gains. Operating income and gross operating margin for the three and nine months ended September 30, 2009 include $18.4 million of such gains.

At September 30, 2010, we had $7.5 million of estimated property damage insurance claims outstanding related to windstorms.

**Note 17. Supplemental Cash Flow Information**

The following table provides information regarding the net effect of changes in our operating assets and liabilities for the periods indicated:

| | For the Nine Months Ended September 30, 2010 | For the Nine Months Ended September 30, 2009 |
|---|---|---|
| Decrease (increase) in: | | |
| Accounts and notes receivable – trade | $ 78.9 | $ (551.2) |
| Accounts receivable – related party | 8.8 | 36.0 |
| Inventories | (520.9) | (830.1) |
| Prepaid and other current assets | (67.9) | (6.4) |
| Other assets | 11.5 | (14.1) |
| Increase (decrease) in: | | |
| Accounts payable – trade | 115.2 | (3.1) |
| Accounts payable – related party | 28.5 | 18.9 |
| Accrued product payables | (53.9) | 817.1 |
| Accrued interest | (52.0) | (25.6) |
| Other current liabilities | 33.7 | (37.7) |
| Other liabilities | (5.4) | 21.3 |
| Net effect of changes in operating accounts | $ (423.5) | $ (574.9) |

We incurred liabilities for construction in progress that had not been paid at September 30, 2010 and December 31, 2009, of $160.7 million and $182.6 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed 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 producer well tie-ins. These amounts are included under the caption “Contributions in aid of construction costs” on the Unaudited Condensed Statements of Consolidated Cash Flows.

In September 2010, we acquired EPCO’s ownership interests in ETC in exchange for 523,306 of our common units. Since we and EPCO are under common control, we recorded the net assets of ETC based on EPCO’s historical basis of $30.6 million. This transaction resulted in increases of $21.9 million of current assets, $14.4 million of property, plant and equipment, $0.1 million of other assets, $5.8 million of current liabilities, and $30.6 million of equity. See Note 13 for additional information regarding this related party transaction.

See Note 16 for information regarding cash proceeds from insurance claims.

**Note 18. Condensed Consolidating Financial Information**

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.

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of Duncan Energy Partners' debt obligations and the remaining debt obligations of TEPPCO. 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 consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 10 for additional information regarding our consolidated debt obligations.

Immediately after the closing of the TEPPCO Merger, Enterprise Products Partners L.P. contributed its ownership interests in TEPPCO and TEPPCO GP to EPO. The following condensed consolidating financial information for EPO has been recast to include TEPPCO and TEPPCO GP using the same basis of presentation described in Note 1 for our consolidated financial statements.

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Balance Sheet**
**September 30, 2010**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **ASSETS** | | | | | | | |
| **Current assets:** | | | | | | | |
| Cash and cash equivalents | $ -- | $ 59.9 | $ (17.3) | $ 42.6 | $ 0.1 | $ -- | $ 42.7 |
| Restricted cash | 30.9 | 1.6 | -- | 32.5 | -- | -- | 32.5 |
| Accounts and notes receivable – trade, net | 1,332.4 | 1,704.1 | -- | 3,036.5 | -- | 0.1 | 3,036.6 |
| Accounts receivable – related parties | (762.8) | 935.9 | (141.5) | 31.6 | (0.6) | -- | 31.0 |
| Inventories | 1,023.6 | 187.4 | (1.0) | 1,210.0 | -- | -- | 1,210.0 |
| Prepaid and other current assets | 182.8 | 119.2 | (12.0) | 290.0 | 0.6 | -- | 290.6 |
| Total current assets | 1,806.9 | 3,008.1 | (171.8) | 4,643.2 | 0.1 | 0.1 | 4,643.4 |
| **Property, plant and equipment, net** | 1,388.0 | 17,432.1 | (10.1) | 18,810.0 | -- | -- | 18,810.0 |
| **Investments in unconsolidated affiliates** | 20,636.7 | 4,756.4 | (24,528.4) | 864.7 | 10,528.0 | (10,528.0) | 864.7 |
| **Intangible assets, net** | 159.3 | 1,715.8 | (14.8) | 1,860.3 | -- | -- | 1,860.3 |
| **Goodwill** | 473.7 | 1,579.0 | -- | 2,052.7 | -- | -- | 2,052.7 |
| **Other assets** | 268.8 | 125.8 | (154.1) | 240.5 | -- | 1.1 | 241.6 |
| Total assets | $ 24,733.4 | $ 28,617.2 | $ (24,879.2) | $ 28,471.4 | $ 10,528.1 | $ (10,526.8) | $ 28,472.7 |
| **LIABILITIES AND EQUITY** | | | | | | | |
| **Current liabilities:** | | | | | | | |
| Accounts payable – trade | $ 165.9 | $ 362.7 | $ (17.4) | $ 511.2 | $ -- | $ -- | $ 511.2 |
| Accounts payable – related parties | 6.9 | 254.7 | (163.4) | 98.2 | -- | -- | 98.2 |
| Accrued product payables | 1,706.6 | 1,634.1 | (2.1) | 3,338.6 | -- | -- | 3,338.6 |
| Accrued interest | 170.7 | 1.8 | (0.3) | 172.2 | -- | -- | 172.2 |
| Other current liabilities | 149.3 | 329.9 | (8.8) | 470.4 | -- | 0.1 | 470.5 |
| Total current liabilities | 2,199.4 | 2,583.2 | (192.0) | 4,590.6 | -- | 0.1 | 4,590.7 |
| **Long-term debt** | 12,063.5 | 650.2 | (8.9) | 12,704.8 | -- | -- | 12,704.8 |
| **Long-term notes payable affiliates** | -- | 125.0 | (125.0) | -- | -- | -- | -- |
| **Deferred tax liabilities** | 3.8 | 71.2 | -- | 75.0 | -- | -- | 75.0 |
| **Other long-term liabilities** | 119.2 | 147.4 | -- | 266.6 | -- | -- | 266.6 |
| **Commitments and contingencies** | | | | | | | |
| **Equity:** | | | | | | | |
| Partners’ and other owners’ equity | 10,347.5 | 21,331.5 | (21,384.1) | 10,294.9 | 10,528.1 | (10,514.9) | 10,308.1 |
| Noncontrolling interests | -- | 3,708.7 | (3,169.2) | 539.5 | -- | (12.0) | 527.5 |
| Total equity | 10,347.5 | 25,040.2 | (24,553.3) | 10,834.4 | 10,528.1 | (10,526.9) | 10,835.6 |
| Total liabilities and equity | $ 24,733.4 | $ 28,617.2 | $ (24,879.2) | $ 28,471.4 | $ 10,528.1 | $ (10,526.8) | $ 28,472.7 |

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Balance Sheet**
**December 31, 2009**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **ASSETS** | | | | | | | |
| **Current assets:** | | | | | | | |
| Cash and cash equivalents | $ 14.4 | $ 46.3 | $ (6.2) | $ 54.5 | $ -- | $ 0.2 | $ 54.7 |
| Restricted cash | 63.1 | 0.5 | -- | 63.6 | -- | -- | 63.6 |
| Accounts and notes receivable – trade, net | 1,595.8 | 1,508.1 | (4.9) | 3,099.0 | -- | -- | 3,099.0 |
| Accounts receivable – related parties | (1,086.2) | 1,165.9 | (40.8) | 38.9 | (0.3) | (0.2) | 38.4 |
| Inventories | 595.4 | 120.3 | (3.8) | 711.9 | -- | -- | 711.9 |
| Prepaid and other current assets | 185.4 | 100.6 | (6.7) | 279.3 | -- | -- | 279.3 |
| Total current assets | 1,367.9 | 2,941.7 | (62.4) | 4,247.2 | (0.3) | -- | 4,246.9 |
| **Property, plant and equipment, net** | 1,436.1 | 16,242.0 | 11.1 | 17,689.2 | -- | -- | 17,689.2 |
| **Investments in unconsolidated affiliates** | 18,981.2 | 5,912.7 | (24,003.3) | 890.6 | 9,512.4 | (9,512.4) | 890.6 |
| **Intangible assets, net** | 170.0 | 910.3 | (15.5) | 1,064.8 | -- | -- | 1,064.8 |
| **Goodwill** | 473.7 | 1,544.6 | -- | 2,018.3 | -- | -- | 2,018.3 |
| **Other assets** | 287.2 | 131.1 | (177.4) | 240.9 | -- | 0.9 | 241.8 |
| Total assets | $ 22,716.1 | $ 27,682.4 | $ (24,247.5) | $ 26,151.0 | $ 9,512.1 | $ (9,511.5) | $ 26,151.6 |
| **LIABILITIES AND EQUITY** | | | | | | | |
| **Current liabilities:** | | | | | | | |
| Current maturities of debt | $ -- | $ 8.9 | $ (8.9) | $ -- | $ -- | $ -- | $ -- |
| Accounts payable – trade | 86.5 | 331.2 | (7.1) | 410.6 | -- | -- | 410.6 |
| Accounts payable – related parties | 59.8 | 220.3 | (210.3) | 69.8 | -- | -- | 69.8 |
| Accrued product payables | 1,842.6 | 1,557.3 | (6.9) | 3,393.0 | -- | -- | 3,393.0 |
| Accrued interest | 227.0 | 1.2 | (0.2) | 228.0 | -- | -- | 228.0 |
| Other current liabilities | 176.7 | 264.1 | (6.2) | 434.6 | -- | -- | 434.6 |
| Total current liabilities | 2,392.6 | 2,383.0 | (239.6) | 4,536.0 | -- | -- | 4,536.0 |
| **Long-term debt** | 10,777.6 | 568.8 | -- | 11,346.4 | -- | -- | 11,346.4 |
| **Deferred tax liabilities** | 3.1 | 68.6 | -- | 71.7 | -- | -- | 71.7 |
| **Other long-term liabilities** | 14.8 | 140.4 | -- | 155.2 | -- | -- | 155.2 |
| **Commitments and contingencies** | | | | | | | |
| **Equity:** | | | | | | | |
| Partners’ and other owners’ equity | 9,528.0 | 21,058.3 | (21,084.5) | 9,501.8 | 9,512.1 | (9,501.8) | 9,512.1 |
| Noncontrolling interests | -- | 3,463.3 | (2,923.4) | 539.9 | -- | (9.7) | 530.2 |
| Total equity | 9,528.0 | 24,521.6 | (24,007.9) | 10,041.7 | 9,512.1 | (9,511.5) | 10,042.3 |
| Total liabilities and equity | $ 22,716.1 | $ 27,682.4 | $ (24,247.5) | $ 26,151.0 | $ 9,512.1 | $ (9,511.5) | $ 26,151.6 |

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Statement of Operations**
**Three Months Ended September 30, 2010**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **Revenues** | $ 6,068.5 | $ 4,940.9 | $ (2,941.6) | $ 8,067.8 | $ -- | $ -- | $ 8,067.8 |
| **Costs and expenses:** | | | | | | | |
| Operating costs and expenses | 5,977.6 | 4,425.0 | (2,942.5) | 7,460.1 | -- | -- | 7,460.1 |
| General and administrative costs | 8.1 | 47.6 | -- | 55.7 | 0.3 | -- | 56.0 |
| Total costs and expenses | 5,985.7 | 4,472.6 | (2,942.5) | 7,515.8 | 0.3 | -- | 7,516.1 |
| **Equity in income of unconsolidated affiliates** | 463.1 | 21.4 | (467.0) | 17.5 | 372.2 | (372.2) | 17.5 |
| **Operating income** | 545.9 | 489.7 | (466.1) | 569.5 | 371.9 | (372.2) | 569.2 |
| **Other income (expense):** | | | | | | | |
| Interest expense | (176.2) | (6.4) | 2.9 | (179.7) | -- | -- | (179.7) |
| Interest income | 3.1 | 0.7 | (2.9) | 0.9 | -- | -- | 0.9 |
| Other, net | -- | 0.4 | -- | 0.4 | -- | -- | 0.4 |
| Total other expense, net | (173.1) | (5.3) | -- | (178.4) | -- | -- | (178.4) |
| **Income before provision for income taxes** | 372.8 | 484.4 | (466.1) | 391.1 | 371.9 | (372.2) | 390.8 |
| Provision for income taxes | (1.6) | (3.2) | -- | (4.8) | -- | (0.1) | (4.9) |
| **Net income** | 371.2 | 481.2 | (466.1) | 386.3 | 371.9 | (372.3) | 385.9 |
| Net income attributable to noncontrolling interests | -- | 10.7 | (24.9) | (14.2) | -- | 0.2 | (14.0) |
| **Net income attributable to entity** | $ 371.2 | $ 491.9 | $ (491.0) | $ 372.1 | $ 371.9 | $ (372.1) | $ 371.9 |

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Statement of Operations**
**Three Months Ended September 30, 2009**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **Revenues** | $ 4,843.8 | $ 3,863.8 | $ (1,918.2) | $ 6,789.4 | $ -- | $ -- | $ 6,789.4 |
| **Costs and expenses:** | | | | | | | |
| Operating costs and expenses | 4,766.3 | 3,547.4 | (1,917.9) | 6,395.8 | -- | -- | 6,395.8 |
| General and administrative costs | 3.8 | 40.2 | -- | 44.0 | 8.3 | -- | 52.3 |
| Total costs and expenses | 4,770.1 | 3,587.6 | (1,917.9) | 6,439.8 | 8.3 | -- | 6,448.1 |
| **Equity in income of unconsolidated affiliates** | 272.6 | 50.9 | (308.5) | 15.0 | 221.2 | (221.2) | 15.0 |
| **Operating income** | 346.3 | 327.1 | (308.8) | 364.6 | 212.9 | (221.2) | 356.3 |
| **Other income (expense):** | | | | | | | |
| Interest expense | (124.4) | (39.8) | 3.2 | (161.0) | -- | -- | (161.0) |
| Interest income | 3.1 | 0.4 | (3.2) | 0.3 | -- | -- | 0.3 |
| Other, net | -- | (0.1) | -- | (0.1) | -- | -- | (0.1) |
| Total other expense, net | (121.3) | (39.5) | -- | (160.8) | -- | -- | (160.8) |
| **Income before provision for income taxes** | 225.0 | 287.6 | (308.8) | 203.8 | 212.9 | (221.2) | 195.5 |
| Provision for income taxes | (3.4) | (4.3) | -- | (7.7) | -- | -- | (7.7) |
| **Net income** | 221.6 | 283.3 | (308.8) | 196.1 | 212.9 | (221.2) | 187.8 |
| Net loss attributable to noncontrolling interests | -- | 1.1 | 24.0 | 25.1 | -- | -- | 25.1 |
| **Net income attributable to entity** | $ 221.6 | $ 284.4 | $ (284.8) | $ 221.2 | $ 212.9 | $ (221.2) | $ 212.9 |

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Statement of Operations**
**Nine Months Ended September 30, 2010**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **Revenues** | $ 18,684.4 | $ 14,341.2 | $ (8,869.9) | $ 24,155.7 | $ -- | $ -- | $ 24,155.7 |
| **Costs and expenses:** | | | | | | | |
| Operating costs and expenses | 18,374.1 | 12,903.1 | (8,871.0) | 22,406.2 | -- | -- | 22,406.2 |
| General and administrative costs | 11.0 | 116.0 | -- | 127.0 | 4.5 | -- | 131.5 |
| Total costs and expenses | 18,385.1 | 13,019.1 | (8,871.0) | 22,533.2 | 4.5 | -- | 22,537.7 |
| **Equity in income of unconsolidated affiliates** | 1,296.1 | 117.3 | (1,363.2) | 50.2 | 1,111.4 | (1,111.4) | 50.2 |
| **Operating income** | 1,595.4 | 1,439.4 | (1,362.1) | 1,672.7 | 1,106.9 | (1,111.4) | 1,668.2 |
| **Other income (expense):** | | | | | | | |
| Interest expense | (484.1) | (20.8) | 8.0 | (496.9) | -- | -- | (496.9) |
| Interest income | 8.3 | 1.3 | (8.0) | 1.6 | -- | -- | 1.6 |
| Other, net | 0.2 | -- | -- | 0.2 | -- | -- | 0.2 |
| Total other expense, net | (475.6) | (19.5) | -- | (495.1) | -- | -- | (495.1) |
| **Income before provision for income taxes** | 1,119.8 | 1,419.9 | (1,362.1) | 1,177.6 | 1,106.9 | (1,111.4) | 1,173.1 |
| Provision for income taxes | (9.9) | (10.1) | -- | (20.0) | -- | (0.1) | (20.1) |
| **Net income** | 1,109.9 | 1,409.8 | (1,362.1) | 1,157.6 | 1,106.9 | (1,111.5) | 1,153.0 |
| Net income attributable to noncontrolling interests | -- | 17.3 | (63.9) | (46.6) | -- | 0.5 | (46.1) |
| **Net income attributable to entity** | $ 1,109.9 | $ 1,427.1 | $ (1,426.0) | $ 1,111.0 | $ 1,106.9 | $ (1,111.0) | $ 1,106.9 |

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Statement of Operations**
**Nine Months Ended September 30, 2009**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **Revenues** | $ 12,276.1 | $ 10,140.2 | $ (5,305.7) | $ 17,110.6 | $ -- | $ -- | $ 17,110.6 |
| **Costs and expenses:** | | | | | | | |
| Operating costs and expenses | 12,040.1 | 8,993.9 | (5,237.1) | 15,796.9 | -- | -- | 15,796.9 |
| General and administrative costs | 9.7 | 108.9 | -- | 118.6 | 14.7 | -- | 133.3 |
| Total costs and expenses | 12,049.8 | 9,102.8 | (5,237.1) | 15,915.5 | 14.7 | -- | 15,930.2 |
| **Equity in income of unconsolidated affiliates** | 775.7 | 61.2 | (804.9) | 32.0 | 639.5 | (639.5) | 32.0 |
| **Operating income** | 1,002.0 | 1,098.6 | (873.5) | 1,227.1 | 624.8 | (639.5) | 1,212.4 |
| **Other income (expense):** | | | | | | | |
| Interest expense | (363.6) | (117.8) | 9.4 | (472.0) | -- | -- | (472.0) |
| Interest income | 9.3 | 2.0 | (9.4) | 1.9 | -- | -- | 1.9 |
| Other, net | -- | 0.3 | -- | 0.3 | -- | -- | 0.3 |
| Total other expense, net | (354.3) | (115.5) | -- | (469.8) | -- | -- | (469.8) |
| **Income before provision for income taxes** | 647.7 | 983.1 | (873.5) | 757.3 | 624.8 | (639.5) | 742.6 |
| Provision for income taxes | (7.9) | (18.9) | -- | (26.8) | -- | -- | (26.8) |
| **Net income** | 639.8 | 964.2 | (873.5) | 730.5 | 624.8 | (639.5) | 715.8 |
| Net income attributable to noncontrolling interests | -- | 16.1 | (107.3) | (91.2) | -- | 0.2 | (91.0) |
| **Net income attributable to entity** | $ 639.8 | $ 980.3 | $ (980.8) | $ 639.3 | $ 624.8 | $ (639.3) | $ 624.8 |

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Statement of Cash Flows**
**Nine Months Ended September 30, 2010**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subsidiary Issuer (EPO) | Other Subsidiaries (Non-guarantor) | EPO and Subsidiaries Eliminations and Adjustments | Consolidated EPO and Subsidiaries | Parent Company (Guarantor) | Eliminations and Adjustments | Consolidated Total |
| **Operating activities:** | | | | | | | |
| Net income | $ 1,109.9 | $ 1,409.8 | $ (1,362.1) | $ 1,157.6 | $ 1,106.9 | $ (1,111.5) | $ 1,153.0 |
| Adjustments to reconcile net income to cash provided by operating activities: | | | | | | | |
| Depreciation, amortization and accretion | 84.2 | 621.0 | (1.0) | 704.2 | -- | -- | 704.2 |
| Non-cash asset impairment charges | -- | 1.5 | -- | 1.5 | -- | -- | 1.5 |
| Equity in income of unconsolidated affiliates | (1,296.1) | (117.3) | 1,363.2 | (50.2) | (1,111.4) | 1,111.4 | (50.2) |
| Distributions received from unconsolidated affiliates | 138.3 | 121.9 | (177.9) | 82.3 | 1,273.5 | (1,273.5) | 82.3 |
| Operating lease expenses paid by EPCO | 0.5 | -- | -- | 0.5 | -- | -- | 0.5 |
| Gains from asset sales and related transactions | (0.2) | (45.3) | 0.1 | (45.4) | -- | -- | (45.4) |
| Deferred income tax expense | 0.7 | 3.1 | -- | 3.8 | -- | (0.1) | 3.7 |
| Changes in fair market value of derivative instruments | (10.0) | (0.8) | -- | (10.8) | -- | -- | (10.8) |
| Effect of pension settlement recognition | -- | (0.2) | -- | (0.2) | -- | -- | (0.2) |
| Net effect of changes in operating accounts | 596.1 | (312.9) | (705.9) | (422.7) | (0.9) | 0.1 | (423.5) |
| Cash provided by operating activities | 623.4 | 1,680.8 | (883.6) | 1,420.6 | 1,268.1 | (1,273.6) | 1,415.1 |
| **Investing activities:** | | | | | | | |
| Capital expenditures | 22.7 | (1,427.8) | -- | (1,405.1) | -- | -- | (1,405.1) |
| Contributions in aid of construction costs | 1.6 | 12.3 | -- | 13.9 | -- | -- | 13.9 |
| Decrease (increase) in restricted cash | 39.0 | (1.1) | -- | 37.9 | -- | -- | 37.9 |
| Cash used for business combinations | (2.2) | (1,230.8) | -- | (1,233.0) | -- | -- | (1,233.0) |
| Investments in unconsolidated affiliates | (1,577.2) | (5.5) | 1,576.4 | (6.3) | (1,056.7) | 1,056.7 | (6.3) |
| Repayment of affiliate loan | (45.6) | 45.6 | -- | -- | -- | -- | -- |
| Proceeds from asset sales and related transactions | 0.2 | 89.4 | -- | 89.6 | -- | -- | 89.6 |
| Other investing activities | -- | 1.5 | -- | 1.5 | -- | -- | 1.5 |
| Cash used in investing activities | (1,561.5) | (2,516.4) | 1,576.4 | (2,501.5) | (1,056.7) | 1,056.7 | (2,501.5) |
| **Financing activities:** | | | | | | | |
| Borrowings under debt agreements | 3,965.7 | 138.1 | -- | 4,103.8 | -- | -- | 4,103.8 |
| Repayments of debt | (2,686.8) | (67.0) | -- | (2,753.8) | -- | -- | (2,753.8) |
| Long-term notes payable affiliates | (125.0) | 125.0 | -- | -- | -- | -- | -- |
| Debt issuance costs | (14.7) | -- | -- | (14.7) | -- | -- | (14.7) |
| Cash distributions paid to partners | (1,273.5) | (963.1) | 963.1 | (1,273.5) | (1,263.1) | 1,273.5 | (1,263.1) |
| Unit option-related reimbursements to EPCO | -- | -- | -- | -- | (9.7) | -- | (9.7) |
| Cash distributions paid to noncontrolling interests | -- | (99.1) | 44.9 | (54.2) | -- | 0.2 | (54.0) |
| Cash contributions from noncontrolling interests | -- | 356.7 | (353.6) | 3.1 | -- | (0.3) | 2.8 |
| Net cash proceeds from issuance of common units | -- | -- | -- | -- | 1,058.0 | -- | 1,058.0 |
| Cash proceeds from exercise of unit options | -- | -- | -- | -- | 6.6 | -- | 6.6 |
| Cash contributions from members | 1,056.7 | 1,358.3 | (1,358.3) | 1,056.7 | -- | (1,056.7) | -- |
| Acquisition of treasury units | -- | -- | -- | -- | (3.1) | -- | (3.1) |
| Other financing activities | 1.3 | -- | -- | 1.3 | -- | -- | 1.3 |
| Cash provided by financing activities | 923.7 | 848.9 | (703.9) | 1,068.7 | (211.3) | 216.7 | 1,074.1 |
| **Effect of exchange rate changes on cash** | -- | 0.3 | -- | 0.3 | -- | -- | 0.3 |
| **Net change in cash and cash equivalents** | (14.4) | 13.3 | (11.1) | (12.2) | 0.1 | (0.2) | (12.3) |
| **Cash and cash equivalents, January 1** | 14.4 | 46.3 | (6.2) | 54.5 | -- | 0.2 | 54.7 |
| **Cash and cash equivalents, September 30** | $ -- | $ 59.9 | $ (17.3) | $ 42.6 | $ 0.1 | $ -- | $ 42.7 |

**ENTERPRISE PRODUCTS PARTNERS L.P.**
**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

**Enterprise Products Partners L.P.**
**Unaudited Condensed Consolidating Statement of Cash Flows**
**Nine Months Ended September 30, 2009**

| | EPO and Subsidiaries | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Subsidiary Issuer (EPO)** | **Other Subsidiaries (Non-guarantor)** | **EPO and Subsidiaries Eliminations and Adjustments** | **Consolidated EPO and Subsidiaries** | **Parent Company (Guarantor)** | **Eliminations and Adjustments** | **Consolidated Total** |
| **Operating activities:** | | | | | | | |
| Net income | $ 639.8 | $ 964.2 | $ (873.5) | $ 730.5 | $ 624.8 | $ (639.5) | $ 715.8 |
| Adjustments to reconcile net income to cash provided by operating activities: | | | | | | | |
| Depreciation, amortization and accretion | 58.9 | 562.4 | (1.4) | 619.9 | -- | -- | 619.9 |
| Non-cash asset impairment charges | -- | 26.3 | -- | 26.3 | -- | -- | 26.3 |
| Equity in income of unconsolidated affiliates | (775.7) | (61.2) | 804.9 | (32.0) | (639.5) | 639.5 | (32.0) |
| Distributions received from unconsolidated affiliates | 208.7 | 186.9 | (340.4) | 55.2 | 870.1 | (870.1) | 55.2 |
| Operating lease expenses paid by EPCO | 0.5 | -- | -- | 0.5 | -- | -- | 0.5 |
| Gains from asset sales and related transactions | -- | (0.5) | -- | (0.5) | -- | -- | (0.5) |
| Loss on forfeiture of investment in TOPS | -- | 68.4 | -- | 68.4 | -- | -- | 68.4 |
| Deferred income tax expense | (0.8) | 3.6 | -- | 2.8 | -- | (0.3) | 2.5 |
| Changes in fair market value of derivative instruments | 12.7 | (2.1) | -- | 10.6 | -- | -- | 10.6 |
| Effect of pension settlement recognition | -- | (0.1) | -- | (0.1) | -- | -- | (0.1) |
| Net effect of changes in operating accounts | 204.5 | (854.1) | 69.9 | (579.7) | 4.8 | -- | (574.9) |
| Cash provided by operating activities | 348.6 | 893.8 | (340.5) | 901.9 | 860.2 | (870.4) | 891.7 |
| **Investing activities:** | | | | | | | |
| Capital expenditures | (108.7) | (991.7) | -- | (1,100.4) | -- | -- | (1,100.4) |
| Contributions in aid of construction costs | -- | 12.8 | -- | 12.8 | -- | -- | 12.8 |
| Decrease (increase) in restricted cash | 103.2 | (2.4) | -- | 100.8 | -- | -- | 100.8 |
| Cash used for business combinations | (23.7) | (50.8) | -- | (74.5) | -- | -- | (74.5) |
| Investments in unconsolidated affiliates | (330.1) | (32.8) | 349.0 | (13.9) | (876.1) | 876.1 | (13.9) |
| Proceeds from asset sales and related transactions | -- | 2.9 | -- | 2.9 | -- | -- | 2.9 |
| Other investing activities | -- | 0.1 | -- | 0.1 | -- | -- | 0.1 |
| Cash used in investing activities | (359.3) | (1,061.9) | 349.0 | (1,072.2) | (876.1) | 876.1 | (1,072.2) |
| **Financing activities:** | | | | | | | |
| Borrowings under debt agreements | 3,758.3 | 1,205.5 | -- | 4,963.8 | -- | -- | 4,963.8 |
| Repayments of debt | (3,642.1) | (951.9) | -- | (4,594.0) | -- | -- | (4,594.0) |
| Debt issuance costs | (4.8) | (0.7) | -- | (5.5) | -- | -- | (5.5) |
| Cash distributions paid to partners | (870.1) | (348.0) | 348.0 | (870.1) | (860.1) | 870.1 | (860.1) |
| Unit option-related reimbursements to EPCO | -- | -- | -- | -- | (0.5) | -- | (0.5) |
| Cash distributions paid to noncontrolling interests | -- | (339.2) | 16.8 | (322.4) | -- | 0.1 | (322.3) |
| Cash contributions from noncontrolling interests | -- | 314.6 | (175.9) | 138.7 | -- | -- | 138.7 |
| Net cash proceeds from issuance of common units | -- | -- | -- | -- | 877.7 | -- | 877.7 |
| Cash proceeds from exercise of unit options | -- | -- | -- | -- | 0.5 | -- | 0.5 |
| Cash contributions from members | 876.1 | 188.9 | (188.9) | 876.1 | -- | (876.1) | -- |
| Acquisition of treasury units | -- | -- | -- | -- | (1.8) | -- | (1.8) |
| Cash provided by financing activities | 117.4 | 69.2 | -- | 186.6 | 15.8 | (5.9) | 196.5 |
| **Effect of exchange rate changes on cash** | -- | (0.4) | -- | (0.4) | -- | -- | (0.4) |
| **Net change in cash and cash equivalents** | 106.7 | (98.9) | 8.5 | 16.3 | (0.1) | (0.2) | 16.0 |
| **Cash and cash equivalents, January 1** | 1.0 | 69.7 | (9.4) | 61.3 | 0.2 | 0.2 | 61.7 |
| **Cash and cash equivalents, September 30** | $ 107.7 | $ (29.6) | $ (0.9) | $ 77.2 | $ 0.1 | $ -- | $ 77.3 |

**Note 19. Subsequent Event**

On November 1, 2010, we acquired certain assets from Cenac Towing Co., L.L.C., Cenac Offshore, L.L.C., CTCO Marine Services, LLC, and CTCO Shipyard of Louisiana, LLC relating to their shipyard operations in Louisiana and certain membership interests in CTCO of Texas, L.L.C. and Channelview Fleeting Services, LLC relating to shipyard operations in Texas. Since we entered into the marine transportation business in 2008, we have paid the above entities for services to support this business including construction, repairs and maintenance, drydock and provisioning services. We expect these acquired assets will result in significant future cost savings for our marine fleet.

This transaction is valued at approximately $140.0 million and the consideration consists of approximately $42.3 million in cash and $97.7 million of our common units (represented by approximately 2.3 million common units). We will account for this business combination using the purchase method of accounting. Accordingly, such costs will be allocated to assets acquired and liabilities assumed based on fair values developed using recognized business valuation techniques. Our preliminary purchase price allocation for this transaction is as follows: $80.0 million for property, plant and equipment; $12.5 million for intangible assets (principally a non-compete agreement); and $47.5 million of goodwill. The goodwill in this transaction is attributed to our expectation that owning these assets will result in significant future cost savings for our marine fleet.

**Item 2.** ***Management's Discussion and Analysis of Financial Condition and Results of Operations*.**

**For the three and nine months ended September 30, 2010 and 2009.**

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this quarterly report on Form 10-Q. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2009 (the "2009 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States.

**Key References Used in this Quarterly Report**

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, which is a wholly owned subsidiary of Enterprise Products Partners. Enterprise Products Partners conducts substantially all of its business through EPO and its consolidated subsidiaries. References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner. EPGP is responsible for managing the business and operations of Enterprise Products Partners.

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 "Holdings" mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Holdings owns EPGP. On September 3, 2010, we and Holdings entered into an Agreement and Plan of Merger (the "Holdings Merger Agreement") that would, if approved by Holdings' unitholders, result in the merger of Holdings with a wholly owned subsidiary of ours through a unit-for-unit exchange (the "Holdings Merger"). See "Significant Recent Developments" included within this Item 2 for additional information regarding the proposed Holdings Merger. The general partner of Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiar y of Dan Duncan LLC.

The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the "DD LLC Voting Trust Agreement"), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the "DD LLC Trustees") are: (i) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also a director of EPE Holdings; (ii) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (iii) Richard H. Bachmann, who is currently an Executive Vice President, the Chief Legal Officer and Secretary of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann also serve as directors of EPE Holdings.

The DD LLC Voting Trust Agreement requires that there always be two "Independent Voting Trustees" serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within 90 days of the vacancy's occurrence, the CEO of our general partner, currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a "Duncan Voting Trustee." The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. For all purposes whatsoever, the DD LLC Trustees are required to treat the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan LLC. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take party in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and, subject to the provisions of the DD LLC Voting Trust Agreement, to rece ive distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, EPO, Duncan Energy Partners, DEP GP, EPGP, Holdings and EPE Holdings were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO, Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger."

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") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC.

References to the "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010.

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* |
| *TBtus* | *= trillion British thermal units* |

**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 the 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. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Item 1A "Risk Factors" included in our 2009 Form 10-K and in Part II, Item 1A of this quarterly report on Form 10-Q. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.*

**Overview of Business**

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. 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.

Our midstream energy operations include: natural gas transportation, gathering, processing and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and storage; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our portfolio of integrated assets includes: 49,100 miles of natural gas, NGL, crude oil, refined products and petrochemical pipelines; 200 MMBbls of NGL, refined products and crude oil storage capacity; 27 Bcf of natural gas storage capacity; and 25 natural gas processing plants. In addition, our asset portfolio includes 18 fractionation faci lities, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and an octane enhancement facility.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services and (v) Petrochemical & Refined Products Services. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner.

We are owned 98% by our limited partners and 2% by our general partner, EPGP. We, EPGP, Holdings, EPE Holdings, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement or by other service providers.

**Basis of Financial Statement Presentation**

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Due to common control considerations, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. As a result, our consolidated financial statements and business segments were recast to reflect the TEPPCO Merger. Our recast consolidated financial statements for periods prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are presented as "Former owners of TEPPCO," which is a component of noncontrolling interest.& #160; Investors should use our recast consolidated financial statements when making comparisons between our current and prior period financial information.

**Significant Recent Developments**

The following information highlights significant developments since January 1, 2010 through the date of this filing, including (i) information relevant to an understanding of our financial condition, changes in financial condition or results of operations, and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations. For a discussion of the offshore drilling moratorium and other regulatory matters, see Part II, Item 1A "Risk Factors."

***Duncan Energy Partners Executes $1.25 Billion in New Credit Facilities***

On October 25, 2010, Duncan Energy Partners entered into new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. The new Duncan Energy Partners credit facilities mature in October 2013 and consist of: (i) an $850.0 million multi-year revolving credit facility (the “DEP Multi-Year Revolving Credit Facility”) and (ii) a $400.0 million term loan facility (the “DEP $400 Million Term Loan Facility”). At closing, Duncan Energy Partners borrowed the full amount available under the DEP $400 Million Term Loan Facility to repay amounts outstanding under the DEP Revolving Credit Facility and an intercompany loan with EPO. Upon repayment, the DEP Revolving Credit Facility along with the loan agreement with EPO were terminated.& #160; Duncan Energy Partners’ existing $282.3 million DEP Term Loan remains in place and is scheduled to mature in December 2011.

Duncan Energy Partners entered into the new $1.25 billion credit agreements primarily to address its funding requirements for 66% of the Haynesville Extension project. Variable interest rates charged under the new credit facilities are based on the London InterBank Offered Rate (or “LIBOR”) or a base rate, both as defined in the agreement.

***Proposed Merger of Holdings with Enterprise Products Partners***

On September 3, 2010, we and Holdings entered into an Agreement and Plan of Merger that would, if approved by Holdings’ unitholders, result in the merger of Holdings with a wholly owned subsidiary of ours through a unit-for-unit exchange. Consequently, Holdings would become a wholly owned subsidiary of ours. Under the terms of the Holdings Merger Agreement, Holdings’ unitholders will be entitled to receive 1.5 of our common units in exchange for each Holdings limited partner unit they own at closing. As a result, we expect to issue, in the aggregate, 208,813,477 of our common units to Holdings’ unitholders. The proposed transaction would also result in the cancellation of 21,563,177 of our common units currently held by Holdings as well as our general partner’s 2 % economic interest and its incentive distribution rights in us. Affiliates of EPCO will continue to own our general partner following the merger.

The proposed merger must receive the affirmative vote of Holdings’ unitholders owning at least a majority of Holdings’ outstanding units as of the record date. Subject to the terms and conditions of a support agreement, privately held affiliates of EPCO (the “Holdings supporting unitholders”) have agreed to vote their 105,739,220 Holdings’ units, representing approximately 76% of Holdings’ outstanding units, in favor of the proposed merger. The support agreement will automatically terminate on December 31, 2010 or upon the earlier termination of the Holdings Merger Agreement. The Holdings supporting unitholders may terminate their obligations under the support agreement in certain circumstances, including specified changes in U.S. federal income tax law if such changes occur prior to the closing of the merger.

In connection with the proposed merger, a privately held affiliate of EPCO has agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us on an initial amount of 30,610,000 of our common units (the “Designated Units”) for a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver would apply is as follows for distributions to be paid during the following periods, if any: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015.

The Holdings Merger Agreement contains customary representations and warranties and covenants by each of the parties. Completion of the proposed merger is conditioned upon, among other things: (i) the absence of certain legal impediments prohibiting the transactions, (ii) applicable regulatory approvals and (iii) the conditions precedent contained in the Holdings Merger Agreement having been satisfied. The Holdings Merger Agreement contains provisions granting us and Holdings the right to terminate the agreement for certain reasons, including, among others, if the proposed merger d oes not occur on or before December 31, 2010.

***Expansion of Eagle Ford Shale Capabilities with New Construction Projects***

We continue to expand our midstream asset capabilities in the Eagle Ford Shale and recently announced new commercial agreements with several major producers including EOG Resources, Inc., Anadarko Petroleum Corporation ("Anadarko") and Pioneer Natural Resources USA, Inc. In June 2010, we announced several new natural gas and NGL infrastructure construction projects to accommodate growing production volumes from the Eagle Ford Shale supply basin in South Texas. We plan to install approximately 360 miles of pipelines, build a new natural gas processing facility in South Texas and construct a 75 MBPD NGL fractionator at our Mont Belvieu complex. Following completion of these construction projects, which is expected in mid-2012, we will have the capability to gather, transport and process almos t 2.1 Bcf/d of natural gas and produce more than 150 MBPD of NGLs from the Eagle Ford Shale.

The planned construction projects include an expansion of our Eagle Ford east-west rich natural gas mainline that will involve adding three additional pipeline segments totaling 168 miles. Upon completion, the rich gas mainline system and associated laterals will consist of approximately 300 miles of pipelines representing gathering and transportation capacity of more than 600 MMcf/d. The east end of the Eagle Ford mainline will terminate at a new cryogenic natural gas processing facility we plan to build that will produce in excess of 60 MBPD of mixed NGLs. Takeaway capacity for residue gas from the new processing facility will be provided by a combination of our existing infrastructure and construction of additional natural gas pipelines, including a new 64-mile, 36-inch diameter pipeline that termin ates at our Wilson natural gas storage facility. An expansion project to increase capacity at the Wilson gas storage facility by 5 Bcf is currently underway.

Transportation of mixed NGLs from our new processing facility to our Mont Belvieu complex will be accomplished by expanding our infrastructure, highlighted by the planned construction of a new 127-mile, 16-inch diameter NGL pipeline. This new pipeline will have an initial transportation capacity of more than 60 MBPD, and will be readily expandable to over 210 MBPD if needed. To accommodate expected volumes from the Eagle Ford Shale and other producing regions, we plan to construct a fifth NGL fractionator with a design capacity of 75 MBPD at our Mont Belvieu complex. The addition of this fifth unit will increase NGL fractionation capacity at our Mont Belvieu complex to approximately 375 MBPD.

In addition to the natural gas and NGL projects described above, we are also constructing a 140-mile crude oil pipeline and associated storage assets that will serve producers in the Eagle Ford Shale basin. This new pipeline will facilitate crude oil deliveries to the Cushing and Houston markets and is expected to be completed in the fourth quarter of 2011.

***Operations Commence at New Port Arthur Refined Products Storage Facility***

In June 2010, we announced that the partnership's new refined products storage facility in Port Arthur, Texas, which was built to support the expansion of a nearby third-party refinery, had commenced commercial operations and received its first deliveries. The new tank farm serves as the sole distribution point for output from the refinery as part of a 15-year throughput and volume dedication agreement. Our Port Arthur storage facility, which represents an investment of approximately $330.0 million, features 5.4 MMBbls of storage capacity for gasoline, diesel and jet fuel. The storage facility provides our customer with access to several major refined products pipelines, including our Enterprise TE Products Pipeline.

***Acquisition of State Line and Fairplay Natural Gas Gathering Systems***

In May 2010, we acquired 100% ownership of the State Line and Fairplay natural gas gathering systems and related assets from M2 Midstream LLC ("Momentum") for approximately $1.2 billion in cash. These systems are located in northwest Louisiana and east Texas and gather natural gas produced from the Haynesville/Bossier Shales and the Cotton Valley and Taylor Sand formations. We used a portion of the net proceeds from our April 2010 equity offering, together with borrowings under EPO's Multi-Year Revolving Credit Facility, to fund this acquisition.

The State Line system is located in Desoto and Caddo Parishes, Louisiana and Panola County, Texas. The system currently includes approximately 188 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 700 MMcf/d and two natural gas treating facilities. The State Line system began operations in February 2009 and is currently gathering approximately 375 MMcf/d of natural gas. The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas. The system includes approximately 249 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 285 MMcf/d. The Fairplay system is currently gathering approximately 150 MMcf/d of natural gas. Our operations related to the Fairplay sys tem include providing natural gas processing services using third-party processing facilities. The State Line and Fairplay systems are supported by long-term acreage dedication agreements totaling approximately 210,000 acres, as well as volumetric commitments from producers.

Our acquisition of the State Line system complements our Haynesville Extension natural gas pipeline project. The Haynesville Extension, which is under development by Acadian Gas, is expected to provide shippers with takeaway capacity from the Haynesville Shale producing basin and flexible options for reaching attractive markets for their natural gas, including access to nine interstate gas pipeline systems. The Fairplay system is expected to extend our asset base through planned future interconnects with our Texas Intrastate System, along with supporting deliveries of NGLs into our Panola pipeline and further to our fractionation, storage and distribution complex in Mont Belvieu, Texas.

**Results of Operations**

***Selected Price and Volumetric Data***

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

| | Natural Gas, $/MMBtu (1) | Ethane, $/gallon (2) | Propane, $/gallon (2) | Normal Butane, $/gallon (2) | Isobutane, $/gallon (2) | Natural Gasoline, $/gallon (2) | Polymer Grade Propylene, $/pound (3) | Refinery Grade Propylene, $/pound (3) | Crude Oil, $/barrel (4) |
|---|---|---|---|---|---|---|---|---|---|
| **2009** | | | | | | | | | |
| 1st Quarter | $ 4.91 | $ 0.36 | $ 0.68 | $ 0.87 | $ 0.97 | $ 0.96 | $ 0.26 | $ 0.20 | $ 43.31 |
| 2nd Quarter | $ 3.51 | $ 0.43 | $ 0.73 | $ 0.93 | $ 1.11 | $ 1.21 | $ 0.34 | $ 0.28 | $ 59.79 |
| 3rd Quarter | $ 3.39 | $ 0.47 | $ 0.87 | $ 1.12 | $ 1.19 | $ 1.42 | $ 0.48 | $ 0.43 | $ 68.24 |
| 4th Quarter | $ 4.16 | $ 0.67 | $ 1.09 | $ 1.39 | $ 1.49 | $ 1.64 | $ 0.50 | $ 0.44 | $ 76.19 |
| **2009 Averages** | $ 3.99 | $ 0.48 | $ 0.84 | $ 1.08 | $ 1.19 | $ 1.31 | $ 0.39 | $ 0.34 | $ 61.88 |
| **2010** | | | | | | | | | |
| 1st Quarter | $ 5.30 | $ 0.73 | $ 1.24 | $ 1.52 | $ 1.64 | $ 1.82 | $ 0.63 | $ 0.54 | $ 78.72 |
| 2nd Quarter | $ 4.09 | $ 0.55 | $ 1.08 | $ 1.47 | $ 1.58 | $ 1.81 | $ 0.65 | $ 0.44 | $ 78.03 |
| 3rd Quarter | $ 4.38 | $ 0.48 | $ 1.07 | $ 1.38 | $ 1.43 | $ 1.71 | $ 0.58 | $ 0.44 | $ 76.20 |
| **2010 Averages** | $ 4.59 | $ 0.59 | $ 1.13 | $ 1.46 | $ 1.55 | $ 1.78 | $ 0.62 | $ 0.47 | $ 77.65 |

(1) Natural gas prices are based on Henry-Hub I-FERC commercial index prices.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate as measured on the New York Mercantile Exchange ("NYMEX").

The following table presents our significant average throughput, production and processing volumetric data for the periods indicated. 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 reflect volumes for newly constructed assets from the dates such assets were placed into service and for recently purchased assets from the date of acquisition.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **NGL Pipelines & Services, net:** | | | | |
| NGL transportation volumes (MBPD) | 2,326 | 2,179 | 2,254 | 2,098 |
| NGL fractionation volumes (MBPD) | 476 | 467 | 471 | 456 |
| Equity NGL production (MBPD) | 122 | 116 | 123 | 116 |
| Fee-based natural gas processing (MMcf/d) | 2,722 | 2,247 | 2,795 | 2,685 |
| **Onshore Natural Gas Pipelines & Services, net:** | | | | |
| Natural gas transportation volumes (BBtus/d) | 11,673 | 10,495 | 11,432 | 10,502 |
| **Onshore Crude Oil Pipelines & Services, net:** | | | | |
| Crude oil transportation volumes (MBPD) | 684 | 654 | 678 | 683 |
| **Offshore Pipelines & Services, net:** | | | | |
| Natural gas transportation volumes (BBtus/d) | 1,138 | 1,374 | 1,284 | 1,458 |
| Crude oil transportation volumes (MBPD) | 299 | 369 | 325 | 278 |
| Platform natural gas processing (MMcf/d) | 442 | 694 | 547 | 741 |
| Platform crude oil processing (MBPD) | 17 | 17 | 18 | 10 |
| **Petrochemical & Refined Products Services, net:** | | | | |
| Butane isomerization volumes (MBPD) | 95 | 104 | 89 | 98 |
| Propylene fractionation volumes (MBPD) | 77 | 67 | 78 | 67 |
| Octane enhancement production volumes (MBPD) | 19 | 13 | 14 | 9 |
| Transportation volumes, primarily refined products and petrochemicals (MBPD) | 748 | 762 | 779 | 797 |
| **Total, net:** | | | | |
| NGL, crude oil, refined products and petrochemical transportation volumes (MBPD) | 4,057 | 3,964 | 4,036 | 3,856 |
| Natural gas transportation volumes (BBtus/d) | 12,811 | 11,869 | 12,716 | 11,960 |
| Equivalent transportation volumes (MBPD) (1) | 7,428 | 7,087 | 7,382 | 7,003 |

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

***Comparison of Results of Operations***

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

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Revenues | $ 8,067.8 | $ 6,789.4 | $ 24,155.7 | $ 17,110.6 |
| Operating costs and expenses | 7,460.1 | 6,395.8 | 22,406.2 | 15,796.9 |
| General and administrative costs | 56.0 | 52.3 | 131.5 | 133.3 |
| Equity in income of unconsolidated affiliates | 17.5 | 15.0 | 50.2 | 32.0 |
| Operating income | 569.2 | 356.3 | 1,668.2 | 1,212.4 |
| Interest expense | 179.7 | 161.0 | 496.9 | 472.0 |
| Provision for income taxes | 4.9 | 7.7 | 20.1 | 26.8 |
| Net income | 385.9 | 187.8 | 1,153.0 | 715.8 |
| Net income (loss) attributable to noncontrolling interests | 14.0 | (25.1) | 46.1 | 91.0 |
| Net income attributable to Enterprise Products Partners L.P. | 371.9 | 212.9 | 1,106.9 | 624.8 |

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

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| Gross operating margin by segment: | | | | |
| NGL Pipelines & Services | $ 397.2 | $ 403.4 | $ 1,275.5 | $ 1,118.1 |
| Onshore Natural Gas Pipelines & Services | 154.1 | 108.4 | 391.3 | 391.5 |
| Onshore Crude Oil Pipelines & Services | 35.0 | 34.1 | 87.6 | 126.7 |
| Offshore Pipelines & Services | 68.3 | 22.8 | 232.2 | 83.0 |
| Petrochemical & Refined Products Services | 166.2 | 70.0 | 444.3 | 255.6 |
| Total segment gross operating margin | $ 820.8 | $ 638.7 | $ 2,430.9 | $ 1,974.9 |

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, see “Other Items – Non-GAAP Reconciliations” included within this Item 2. For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

The following table summarizes each business segment’s contribution to revenues (net of eliminations and adjustments) for the periods indicated (dollars in millions):

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **NGL Pipelines & Services:** | | | | |
| Sales of NGLs | $ 3,048.0 | $ 3,015.4 | $ 9,516.5 | $ 7,527.6 |
| Sales of other petroleum and related products | 0.6 | 0.6 | 1.8 | 1.5 |
| Midstream services | 185.9 | 172.9 | 541.8 | 483.8 |
| Total | 3,234.5 | 3,188.9 | 10,060.1 | 8,012.9 |
| **Onshore Natural Gas Pipelines & Services:** | | | | |
| Sales of natural gas | 651.0 | 585.8 | 2,281.8 | 1,639.5 |
| Midstream services | 196.9 | 182.5 | 572.5 | 541.2 |
| Total | 847.9 | 768.3 | 2,854.3 | 2,180.7 |
| **Onshore Crude Oil Pipelines & Services:** | | | | |
| Sales of crude oil | 2,701.4 | 1,991.3 | 7,672.1 | 4,946.1 |
| Midstream services | 24.5 | 18.7 | 69.7 | 60.8 |
| Total | 2,725.9 | 2,010.0 | 7,741.8 | 5,006.9 |
| **Offshore Pipelines & Services:** | | | | |
| Sales of natural gas | 0.2 | 0.3 | 1.0 | 0.9 |
| Sales of crude oil | 2.3 | 2.0 | 6.3 | 3.1 |
| Midstream services | 68.3 | 99.4 | 239.4 | 243.5 |
| Total | 70.8 | 101.7 | 246.7 | 247.5 |
| **Petrochemical & Refined Products Services:** | | | | |
| Sales of other petroleum and related products | 1,056.3 | 597.2 | 2,860.6 | 1,272.0 |
| Midstream services | 132.4 | 123.3 | 392.2 | 390.6 |
| Total | 1,188.7 | 720.5 | 3,252.8 | 1,662.6 |
| **Total consolidated revenues** | $ 8,067.8 | $ 6,789.4 | $ 24,155.7 | $ 17,110.6 |

***Comparison of Three Months Ended September 30, 2010 with Three Months Ended September 30, 2009***

Revenues for the third quarter of 2010 were $8.07 billion compared to $6.79 billion for the third quarter of 2009. The $1.28 billion quarter-to-quarter increase in consolidated revenues is primarily due to higher energy commodity prices and sales volumes during the third quarter of 2010 compared to the third quarter of 2009. These factors accounted for a $1.27 billion quarter-to-quarter increase in consolidated revenues associated with our marketing activities. Collectively, the remainder of our consolidated revenues increased $10.9 million quarter-to-quarter primarily due to contributions from recently acquired and constructed assets.

Operating costs and expenses were $7.46 billion for the third quarter of 2010 compared to $6.40 billion for the third quarter of 2009, a $1.06 billion quarter-to-quarter increase. The cost of sales of our marketing activities increased $1.21 billion quarter-to-quarter primarily due to higher energy commodity prices and sales volumes. Consolidated operating costs and expenses for the third quarter of 2009 include $66.9 million of expenses related to our dissociation from the Texas Offshore Port System ("TOPS") project and expenses aggregating $46.3 million incurred by TEPPCO (prior to the TEPPCO Merger) related to its refined products river terminal business. Operating costs and expenses for the third quarter of 2010 include $6.6 million of the $22.9 million of total expense related to liquidation of the Employee Partnerships in August 2010. The remaining $16.3 million of expense related to the Employee Partnership liquidations is a component of our general and administrative costs for the third quarter of 2010 (see below). Operating costs and expenses for the third quarter of 2010 were reduced by an insurance-related gain of $56.6 million recorded in connection with our disposition of a segment of an offshore natural gas pipeline and certain components of an offshore platform that we elected to retire (dispose of) rather than repair. For additional information regarding insurance-related gains, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report on Form 10-Q. Collectively, the remainder of our consolidated operating costs and expenses increased $19.6 million quarter-to-quarter primarily due to an increase in natural gas processing expenses attributable to higher plant thermal reduction ("PTR").

General and administrative costs were $56.0 million for the third quarter of 2010 compared to $52.3 million for the third quarter of 2009, a $3.7 million quarter-to-quarter increase. The third quarter of 2010 includes $16.3 million of charges related to the Employee Partnership liquidations and $5.8 million of expenses related to the proposed Holdings Merger. General and administrative costs for the third quarter of 2009 included $15.7 million of charges related to the TEPPCO Merger. Collectively, the remainder of our general and administrative costs decreased $2.7 million quarter-to-quarter.

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.04 per gallon during the third quarter of 2010 versus $0.88 per gallon during the third quarter of 2009. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products in Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.38 per MMBtu during the third quarter of 2010 versus $3.39 per MMBtu during the third quarter of 2009. The market price of crude oil (as measured on the NYMEX) averaged $76.20 per barrel during the th ird quarter of 2010 compared to $68.24 per barrel during the third quarter of 2009. See "Selected Price and Volumetric Data" included within this Item 2 for additional information regarding historical energy commodity prices.

Equity in income of our unconsolidated affiliates was $17.5 million for the third quarter of 2010 compared to $15.0 million for the third quarter of 2009. The $2.5 million quarter-to-quarter increase in equity earnings is primarily due to improved results from our investments in K/D/S Promix, LLC ("Promix") and Centennial Pipeline LLC ("Centennial").

Operating income for the third quarter of 2010 was $569.2 million compared to $356.3 million for the third quarter of 2009. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates resulted in the $212.9 million quarter-to-quarter increase in operating income.

Interest expense increased to $179.7 million for the third quarter of 2010 from $161.0 million for the third quarter of 2009. Average debt principal outstanding increased to $12.68 billion during the third quarter of 2010 from $12.20 billion during the third quarter of 2009 primarily due to EPO's issuance of senior notes in October 2009 and May 2010. The $18.7 million quarter-to-quarter increase in interest expense is primarily due to higher debt principal balances outstanding between the periods. Provision for income taxes decreased $2.8 million quarter-to-quarter.

As a result of items noted in the previous paragraphs, our consolidated net income increased $198.1 million quarter-to-quarter to $385.9 million for the third quarter of 2010 compared to $187.8 million for the third quarter of 2009. Net income attributable to noncontrolling interests was $14.0 million for the third quarter of 2010 compared to a net loss of $25.1 million attributable to noncontrolling interests for the third quarter of 2009. Noncontrolling interest for the third quarter of 2009 reflects $42.1 million of net loss attributable to the former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $159.0 million quarter-to-quarter to $371.9 million for the third quarter of 2010 compared to $212.9 million for the third quarter of 2009. Net income attrib utable to Enterprise Products Partners for the third quarter of 2009 did not reflect the financial results of TEPPCO for that period; however, net income attributable to Enterprise Products Partners for the third quarter of 2010 reflects a full quarter of these acquired operations.

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

*NGL Pipelines & Services*. Gross operating margin from this business segment was $397.2 million for the third quarter of 2010 compared to $403.4 million for the third quarter of 2009, a $6.2 million quarter-to-quarter decrease. The third quarter of 2009 includes $1.2 million of gains related to cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding gains from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $223.7 million for the third quarter of 2010 compared to $238.0 million for the third quarter of 2009, a $14.3 million quarter-to-quarter decrease. Equity NGL production increased to 122 MBPD during the third quarter of 2010 from 116 MBPD during the third quarter of 2009 primarily due to increased processing rates at our plants in Texas and the Rocky Mountains. Likewise, fee-based natural gas processing volumes were 2,722 MMcf/d for the third quarter of 2010 compared to 2,247 MMcf/d for the third quarter of 2009 primarily reflecting an increase in fee-based processing volumes at plants in Texas and the Rocky Mountains. Gross operating margin from our NGL marketing activities decreased $23.8 million quarter-to- quarter primarily due to lower sales margins. Gross operating margin for the third quarter of 2010 includes $3.9 million attributable to natural gas processing activities on the recently acquired Fairplay system. Collectively, gross operating margin from the remainder of our natural gas processing activities increased $5.6 million quarter-to-quarter primarily due to the increase in equity NGL production between periods.

Gross operating margin from our NGL pipelines and related storage business was $135.8 million for the third quarter of 2010 compared to $131.0 million for the third quarter of 2009, a $4.8 million quarter-to-quarter increase. Total NGL transportation volumes increased to 2,326 MBPD during the third quarter of 2010 from 2,179 MBPD during the third quarter of 2009. Gross operating margin from these businesses increased $14.6 million quarter-to-quarter primarily due to higher volumes and/or fees at most of our NGL pipeline and storage facilities. Improved results quarter-to-quarter were partially offset by $9.8 million of charges we recorded during the third quarter of 2010 for disputes arising prior to our acquisition of certain pipelines in 2002 and 2004.

Gross operating margin from our NGL fractionation business was $37.7 million for the third quarter of 2010 compared to $33.2 million for the third quarter of 2009. The $4.5 million quarter-to-quarter increase was primarily due to higher revenues from our Mont Belvieu NGL fractionator as a result of increased volumes and fees. NGL fractionation volumes were 476 MBPD during the third quarter of 2010 compared to 467 MBPD during the third quarter of 2009. On average, the fees we charge for NGL fractionation at Mont Belvieu have increased quarter-to-quarter as a result of increased demand for fractionation capacity.

*Onshore Natural Gas Pipelines & Services*. Gross operating margin from this business segment was $154.1 million for the third quarter of 2010 compared to $108.4 million for the third quarter of 2009, a $45.7 million quarter-to-quarter increase. Our onshore natural gas transportation volumes were 11.7 TBtus/d during the third quarter of 2010 compared to 10.5 TBtus/d during the third quarter of 2009. The quarter-to-quarter increase in gathering and transportation volumes is attributable to natural gas production in the Piceance Basin, Haynesville Shale, Barnett Shale, Eagle Ford Shale and the San Juan Basin.

Gross operating margin from our onshore natural gas pipelines and related natural gas marketing business was $141.4 million for the third quarter of 2010 compared to $94.9 million for the third quarter of 2009, a $46.5 million quarter-to-quarter increase. Gross operating margin from our natural gas marketing activities increased $18.0 million quarter-to-quarter primarily due to higher sales margins. Gross operating margin for the third quarter of 2010 includes $12.3 million from the State Line and Fairplay natural gas gathering systems, which we acquired effective May 1, 2010. Collectively, gross operating margin from the remainder of our natural gas pipeline businesses increased $16.2 million quarter-to-quarter primarily due to higher volumes and fees on the San Juan Gathering System and an increase i n firm capacity reservation fees earned by the Sherman Extension of our Texas Intrastate System. The Sherman Extension pipeline began earning firm capacity reservation fees in August 2009. The fees we charge for gathering services on the San Juan Gathering System are typically indexed to natural gas prices, which increased quarter-to-quarter.

Gross operating margin from our natural gas storage business was $12.7 million for the third quarter of 2010 compared to $13.5 million for the third quarter of 2009. The $0.8 million quarter-to-quarter decrease in gross operating margin is primarily due to higher operating expenses during the third quarter of 2010 compared to the third quarter of 2009.

*Onshore Crude Oil Pipelines & Services*. Gross operating margin from this business segment was $35.0 million for the third quarter of 2010 compared to $34.1 million for the third quarter of 2009. The $0.9 million quarter-to-quarter increase in gross operating margin is primarily due to higher pipeline transportation volumes and fees. Crude oil transportation volumes were higher during the third quarter of 2010 compared to the third quarter of 2009 as a result of increased production in the Eagle Ford Shale, Barnett Shale and West Texas. Total onshore crude oil transportation volumes increased to 684 MBPD during the third quarter of 2010 compared to 654 MBPD during the third quarter of 2009. On average, transportation fees increased quarter-to-quarter primarily due to certain tariff increases that went into effect during the fourth quarter of 2009.

*Offshore Pipelines & Services*. Gross operating margin from this business segment was $68.3 million for the third quarter of 2010 compared to $22.8 million for the third quarter of 2009, a $45.5 million increase quarter-to-quarter. Results for the third quarter of 2010 include $8.2 million of gains related to insurance proceeds compared to $18.4 million of such gains in the third quarter of 2009. Additionally, results for the third quarter of 2009 include $66.9 million of expenses related to our dissociation from TOPS. Excluding the effects of the insurance proceeds and the TOPS charge, gross operating margin from this business segment decreased $11.2 million quarter-to-quarter.

In general, our offshore pipelines and platform assets experienced lower volumes quarter-to-quarter primarily due to diminished natural gas and crude oil production activity in the Gulf of Mexico attributable to the federal offshore drilling moratorium, which went into effect in May 2010. We estimate that the drilling moratorium indirectly decreased third quarter of 2010 gross operating margin for this segment by $10 million to $15 million. The moratorium was lifted in October 2010; however, we are uncertain as to when oil and gas production activity in the Gulf of Mexico will return to pre-moratorium levels. For additional information regarding the federal offshore drilling moratorium, see Part II, Item 1A of this quarterly report on Form 10-Q.

In August 2008, we, including TEPPCO, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed TOPS. In April 2009, we and TEPPCO dissociated from TOPS. In September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized approximately

$66.9 million of expense during the third quarter of 2009 in connection with the payment of this cash settlement.

The following paragraphs provide a discussion of segment results excluding insurance-related gains and the charges associated with TOPS.

Gross operating margin from our offshore crude oil pipeline business was $22.2 million for the third quarter of 2010 compared to $27.9 million for the third quarter of 2009, a $5.7 million decrease quarter-to-quarter. Total offshore crude oil transportation volumes were 299 MBPD during the third quarter of 2010 versus 369 MBPD during the third quarter of 2009. The decrease in gross operating margin quarter-to-quarter is primarily due to lower crude oil transportation volumes.

Gross operating margin from our offshore natural gas pipeline business was $9.3 million for the third quarter of 2010 compared to $8.2 million for the third quarter of 2009, a $1.1 million quarter-to-quarter increase. Gross operating margin from our Independence Trail natural gas pipeline decreased $7.2 million quarter-to-quarter primarily due to lower transportation volumes. Collectively, gross operating margin for the remainder of our offshore natural gas pipelines increased $7.9 million quarter-to-quarter, primarily due to lower expenses for our Anaconda and HIOS natural gas systems. Total offshore natural gas transportation volumes were 1.1 TBtus/d during the third quarter of 2010 versus 1.4 TBtus/d during the third quarter of 2009.

Gross operating margin from our offshore platform services business was $28.6 million for the third quarter of 2010 compared to $35.2 million for the third quarter of 2009, a decrease of $6.6 million quarter-to-quarter. Our net platform natural gas processing volumes were 442 MMcf/d during the third quarter of 2010 compared to 694 MMcf/d during the third quarter of 2009. The $6.6 million quarter-to-quarter decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform.

Natural gas volumes on our Independence Hub platform and Independence Trail pipeline decreased to an average of 489 BBtus/d during the third quarter of 2010 from 768 BBtus/d during the third quarter of 2009 due to well depletion, shut-in of the Merganser well operated by Anadarko and another large well watering out. The federal offshore drilling moratorium also slowed exploration and production activities in the deepwater supply basin served by these assets. Recently, volumes on the Independence system have increased to approximately 560 BBtus/d with the restart of the Merganser well and increased production from the Anadarko-operated Jubilee well.

*Petrochemical & Refined Products Services*. Gross operating margin from this business segment was $166.2 million for the third quarter of 2010 compared to $70.0 million for the third quarter of 2009, a $96.2 million increase quarter-to-quarter.

Gross operating margin from propylene fractionation and related activities was $53.1 million for the third quarter of 2010 compared to $23.2 million for the third quarter of 2009. The $29.9 million quarter-to-quarter increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins. Propylene fractionation volumes increased to 77 MBPD during the third quarter of 2010 from 67 MBPD during the third quarter of 2009. Propylene sales margins increased quarter-to-quarter as a result of improved consumer demand for propylene derivative products and lower propylene production from ethylene crackers (which impacted supply) during the third quarter of 2010 relative to the third quarter of 2009.

Gross operating margin from octane enhancement was $20.6 million for the third quarter of 2010 compared to $5.3 million for the third quarter of 2009. The $15.3 million quarter-to-quarter increase in gross operating margin is primarily due to higher sales volumes and margins from motor gasoline additives and revenues from by-product sales. Octane enhancement production volumes were 19 MBPD during the third quarter of 2010 compared to 13 MBPD during the third quarter of 2009.

Gross operating margin from butane isomerization was $23.1 million for the third quarter of 2010 compared to $22.5 million for the third quarter of 2009. The $0.6 million quarter-to-quarter increase in gross operating margin is primarily due to higher commodity prices resulting in increased revenues from by-product sales. Isomerization volumes during the third quarter of 2010 were 95 MBPD versus 104 MBPD in the third quarter of last year.

Gross operating margin from refined products pipelines and related activities was $51.0 million for the third quarter of 2010 compared to $2.4 million for the third quarter of 2009, a $48.6 million quarter-to-quarter increase. Gross operating margin for the third quarter of 2009 includes a $28.7 million charge for pipeline throughput deficiency fees owed to a third party. This charge was recognized in connection with TEPPCO's river terminal business prior to the TEPPCO Merger. Gross operating margin for the third quarter of 2010 includes $3.2 million from our new Port Arthur, Texas refined products terminal, which was placed in service in June 2010. Collectively, gross operating margin from the remainder of our refined products pipelines and related activities increased $16.7 million q uarter-to-quarter primarily due to higher average pipeline transportation fees on the Enterprise Products Pipeline System and an increase in refined products marketing activity. Pipeline transportation volumes for the refined products business were 606 MBPD during the third quarter of 2010 compared to 630 MBPD during the third quarter of 2009.

Gross operating margin from marine transportation and other segment services was $18.4 million for the third quarter of 2010 compared to $16.6 million for the third quarter of 2009. The $1.8 million quarter-to-quarter increase in gross operating margin is primarily due to the expansion of our fleet of marine vessels since the third quarter of 2009 and improved fleet utilization rates.

***Comparison of Nine Months Ended September 30, 2010 with Nine Months Ended September 30, 2009***

Revenues for the first nine months of 2010 were $24.16 billion compared to $17.11 billion for the first nine months of 2009. The $7.05 billion period-to-period increase in consolidated revenues is primarily due to higher energy commodity prices and sales volumes during the first nine months of 2010 compared to the first nine months of 2009. These factors accounted for a $6.95 billion period-to-period increase in consolidated revenues associated with our marketing activities. Collectively, the remainder of our consolidated revenues increased $95.7 million period-to-period due to various factors including additional revenues from recently acquired and constructed assets.

Operating costs and expenses were $22.41 billion for the first nine months of 2010 compared to $15.80 billion for the first nine months of 2009, a $6.61 billion period-to-period increase. The cost of sales of our marketing activities increased $6.27 billion period-to-period primarily due to higher energy commodity prices and sales volumes. Likewise, the operating costs and expenses of our natural gas processing plants increased $454.4 million period-to-period primarily due to higher PTR costs attributable to an increase in natural gas prices and processing volumes. Consolidated operating costs and expenses for the first nine months of 2009 include aggregate charges of $135.3 million related to our dissociation from TOPS and expenses of $46.3 million incurred by TEPPCO related to its refined products ri ver terminal business. Operating costs and expenses for the first nine months of 2010 include $6.6 million of expense related to the Employee Partnership liquidations and $56.6 million of insurance-related gains recorded in connection with our disposition of certain offshore assets. Collectively, the remainder of our consolidated operating costs and expenses increased $111.8 million period-to-period due to various factors including expenses from recently acquired and constructed assets.

General and administrative costs were $131.5 million for the first nine months of 2010 compared to $133.3 million for the first nine months of 2009, a $1.8 million period-to-period decrease. The first nine months of 2010 include $16.3 million of expense related to the Employee Partnership liquidations and $5.8 million of expenses related to the proposed Holdings Merger. General and administrative costs for the first nine months of 2009 include $26.8 million of charges related to the TEPPCO Merger. Collectively, the remainder of our general and administrative costs increased $2.9 million period-to-period.

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.13 per gallon during the first nine months of 2010 versus $0.77 per gallon during the first nine months of 2009 – a 47% period-to-period increase. The Henry Hub market price of natural gas averaged $4.59 per MMBtu during the first nine months of 2010 versus $3.93 per MMBtu during the first nine months of 2009. The NYMEX crude oil market price averaged $77.65 per barrel during the first nine months of 2010 compared to $57.11 per barrel during the first nine months of 2009 – a 36% period-to-period increase.

Equity in income of our unconsolidated affiliates was $50.2 million for the first nine months of 2010 compared to $32.0 million for the first nine months of 2009, an $18.2 million period-to-period increase. Collectively, equity in income from our investments in midstream energy companies operating in the Gulf of Mexico increased $10.9 million period-to-period primarily due to higher transportation volumes on assets owned by Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”). Equity in income from the remainder of our investments increased $7.3 million period-to-period primarily due to improved results from Promix and Centennial.

Operating income for the first nine months of 2010 was $1.67 billion compared to $1.21 billion for the first nine months of 2009. Collectively, the changes in revenues, costs and expenses and equity in income of unconsolidated affiliates described above resulted in the $455.8 million period-to-period increase in operating income.

Interest expense increased to $496.9 million for the first nine months of 2010 from $472.0 million for the first nine months of 2009. The $24.9 million period-to-period increase in interest expense is primarily due to EPO's issuance of senior notes during October 2009 and May 2010.

Provision for income taxes decreased $6.7 million period-to-period primarily due to a one-time charge associated with taxable gains arising from the sale of certain assets by Dixie Pipeline Company (“Dixie”) during the first quarter of 2009.

As a result of items noted in the previous paragraphs, our consolidated net income increased $437.2 million period-to-period to $1.15 billion for the first nine months of 2010 compared to $715.8 million for the first nine months of 2009. Net income attributable to noncontrolling interests was $46.1 million for the first nine months of 2010 compared to $91.0 million for the first nine months of 2009. Noncontrolling interest for the first nine months of 2009 reflects $48.5 million of net income attributable to the former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $482.1 million period-to-period to $1.11 billion for the first nine months of 2010 compared to $624.8 million for the first nine months of 2009. Net income attributable to Enterprise Products P artners for the nine months ended September 30, 2009 did not reflect the financial results of TEPPCO for that period; however, net income attributable to Enterprise Products Partners for the nine months ended September 30, 2010 reflects nine months of these acquired operations.

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

*NGL Pipelines & Services*. Gross operating margin from this business segment was $1.28 billion for the first nine months of 2010 compared to $1.12 billion for the first nine months of 2009, a $157.4 million period-to-period increase. The first nine months of 2009 include $1.8 million of gains related to cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding gains from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $751.3 million for the first nine months of 2010 compared to $651.4 million for the first nine months of 2009, a $99.9 million period-to-period increase. Equity NGL production increased to 123 MBPD during the first nine months of 2010 from 116 MBPD during the first nine months of 2009. Our Rocky Mountains natural gas processing plants contributed $61.4 million of the period-to-period increase in gross operating margin primarily due to increased equity NGL production. Gross operating margin from our NGL marketing activities increased $21.8 million period-to-period due to higher sales volumes and margins. Gross operating margin for the first nine months of 2010 includes $5.9 million attributable to natural gas processing activities on the recently acquired Fairplay system. Collectively, gross operating margin from the remainder of our natural gas processing activities increased $10.8 million period-to-period primarily due to higher natural gas processing margins in Louisiana and Texas.

Gross operating margin from our NGL pipelines and related storage business was $424.8 million for the first nine months of 2010 compared to $363.8 million for the first nine months of 2009, a $61.0 million period-to-period increase. Total NGL transportation volumes increased to 2,254 MBPD during the first nine months of 2010 from 2,098 MBPD during the first nine months of 2009. Gross operating margin from our Louisiana NGL pipelines increased $20.2 million period-to-period primarily due to a 36 MBPD increase in throughput volumes and an increase in certain transportation tariffs. Gross operating margin from Dixie increased $15.3 million period-to-period, which reflects a 9 MPBD increase in transportation volumes. Gross operating margin from our Houston Ship Channel import/export termina l operations and a related pipeline increased $14.3 million period-to-period primarily due to increased volumes. Overall, volumes handled by our Houston Ship Channel import and export terminals and a related pipeline increased 52 MBPD period-to-period. Gross operating margin from our storage and related terminal businesses increased $19.2 million period-to-period primarily due to higher storage volumes and fees, with our Mont Belvieu storage facility contributing $9.1 million of this increase. In addition, gross operating margin for the first nine months of 2010 includes $4.5 million from our Rio Grande pipeline, which we acquired in the fourth quarter of 2009. Improved results from these assets were partially offset by a combined $7.1 million decrease in gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals primarily due to increased operating costs. Gross operating margin from the remaining NGL pipelines decreased $5 .4 million period-to-period, primarily due to a $6.8 million charge we recorded during the third quarter of 2010 for a dispute arising prior to our September 2004 acquisition of a pipeline in south Texas.

Gross operating margin from our NGL fractionation business was $99.4 million for the first nine months of 2010 compared to $101.1 million for the first nine months of 2009, a $1.7 million decrease period-to-period. Gross operating margin from our Norco fractionator decreased $10.0 million period-to-period primarily due to hedging and operating gains during the 2009 period. Collectively, gross operating margin from the remainder of our NGL fractionators increased $8.3 million period-to-period, primarily due to improved results from our Mont Belvieu and Promix NGL fractionation facilities. Fractionation volumes were 471 MBPD during the first nine months of 2010 compared to 456 MBPD during the first nine months of 2009.

*Onshore Natural Gas Pipelines & Services*. Gross operating margin from this business segment was $391.3 million for the first nine months of 2010 compared to $391.5 million for the first nine months of 2009, a $0.2 million period-to-period decrease. Our onshore natural gas transportation volumes were 11.4 TBtus/d during the first nine months of 2010 compared to 10.5 TBtus/d during the first nine months of 2009.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $352.8 million for the first nine months of 2010 compared to $352.6 million for the first nine months of 2009, a $0.2 million period-to-period increase. Gross operating margin for the first nine months of 2010 includes $19.3 million from the State Line and Fairplay natural gas gathering systems, which we acquired effective May 1, 2010. Gross operating margin from our Texas Intrastate System increased $18.5 million period-to-period primarily due to higher firm capacity reservation fees on the Sherman Extension pipeline. Collectively, gross operating margin from the remainder of our onshore natural gas pipelines and related marketing activities decreased $37.6 million period-to-period primarily due to lower s ales margins and higher transportation and storage expenses associated with our natural gas marketing activities.

Natural gas basis differentials in Texas (specifically, the difference in natural gas prices between markets in west Texas and east Texas) were significantly lower during the first nine months of 2010 relative to the first nine months of 2009. The period-to-period decrease in basis differentials resulted in lower sales margins associated with our natural gas marketing activities and lower pipeline throughput volumes during the first nine months of 2010.

Gross operating margin from our natural gas storage business was $38.5 million for the first nine months of 2010 compared to $38.9 million for the first nine months of 2009. The $0.4 million period-to-period decrease in gross operating margin is primarily due to higher operating expenses during the first nine months of 2010 compared to the first nine months of 2009.

*Onshore Crude Oil Pipelines & Services*. Gross operating margin from this business segment was $87.6 million for the first nine months of 2010 compared to $126.7 million for the first nine months of 2009, a $39.1 million decrease period-to-period. Total onshore crude oil transportation volumes decreased to 678 MBPD during the first nine months of 2010 compared to 683 MBPD during the first nine months of 2009. The period-to-period decrease in gross operating margin is primarily due to lower sales margins associated with our crude oil marketing activities resulting from a competitive crude oil marketing environment (e.g., lower basis differentials period-to-period) and higher pipeline and truck transportation costs.&# 160; Basis differentials represent the difference in crude oil prices between two locations or price differences for various qualities of crude oil (e.g., “sweet” crude versus “sour” crude).

*Offshore Pipelines & Services*. Gross operating margin from this business segment was $232.2 million for the first nine months of 2010 compared to $83.0 million for the first nine months of 2009, a $149.2 million increase period-to-period. Results for the first nine months of 2010 include $27.5 million of gains related to insurance proceeds compared to $18.4 million of such gains in the first nine months of 2009. Results for the first nine months of 2009 include $135.3 million of charges related to our dissociation from TOPS, of which $68.4 million was recorded in April 2009 upon our dissociation and $66.9 million in September 2009 related to a final settlement of TOPS-related disputes. As discussed in th e following paragraphs, gross operating margin from this business segment increased $4.8 million period-to-period excluding the effects of insurance proceeds and charges related to TOPS.

Gross operating margin from our offshore crude oil pipeline business was $73.4 million for the first nine months of 2010 compared to $47.3 million for the first nine months of 2009, $26.1 million period-to-period increase. Gross operating margin from our Shenzi crude oil pipeline, which commenced operations in April 2009, increased $10.2 million period-to-period. In addition, equity earnings from Poseidon increased $7.8 million period-to-period primarily due to higher transportation volumes. Collectively, gross operating margin from the remainder of our crude oil pipelines increased $8.1 million period-to-period primarily due to increased transportation volumes. Certain of these pipelines were either in limited service or out-of-service completely during the first nine months of 2009 due to the lingering effects of Hurricanes Gustav and Ike on energy infrastructure in the Gulf of Mexico. With respect to the 2010 period, our offshore pipelines and platform assets have experienced lower volumes since May 2010 due to diminished natural gas and crude oil production activity in the Gulf of Mexico attributable to the federal offshore drilling moratorium. The moratorium was lifted in October 2010; however, we are uncertain as to when oil and gas production activity in the Gulf of Mexico will return to pre-moratorium levels. Despite these conditions, total offshore crude oil transportation volumes averaged 325 MBPD during the first nine months of 2010 compared to 278 MBPD during the first nine months of 2009.

Gross operating margin from our offshore natural gas pipeline business was $35.6 million for the first nine months of 2010 compared to $42.7 million for the first nine months of 2009. The $7.1 million period-to-period decrease in gross operating margin is primarily due to lower transportation volumes on our Independence Trail pipeline. Natural gas transportation volumes on our Independence Trail pipeline decreased to 613 BBtus/d during the first nine months of 2010 from 860 BBtus/d during the first nine months of 2009. The period-to-period decline in volumes for our Independence Trail pipeline and Independence Hub platform is primarily due to well depletion, shut-in of the Merganser well, another large well watering out, and indirect impacts of the federal offshore drilling moratorium. As no ted previously, volumes for our Independence Trail and Hub assets have recently increased due to the restart of wells and increased volumes from producing wells. Total offshore natural gas transportation volumes were 1,284 BBtus/d during the first nine months of 2010 versus 1,458 BBtus/d during the first nine months of 2009.

Gross operating margin from our offshore platform services business was $95.7 million for the first nine months of 2010 compared to $109.9 million for the first nine months of 2009, a $14.2 million decrease period-to-period.  Our net platform natural gas processing volumes were 547 MMcf/d during the first nine months of 2010 compared to 741 MMcf/d during the first nine months of 2009.  The period-to-period decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform for the reasons stated in the previous paragraph.

*Petrochemical & Refined Products Services*.  Gross operating margin from this business segment was $444.3 million for the first nine months of 2010 compared to $255.6 million for the first nine months of 2009, a $188.7 million increase period-to-period.

Gross operating margin from propylene fractionation and related activities was $163.8 million for the first nine months of 2010 compared to $68.8 million for the first nine months of 2009.  The $95.0 million period-to-period increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins.  As noted previously, propylene sales margins increased period-to-period as a result of improved consumer demand for propylene derivative products and lower propylene production from ethylene crackers (which impacted supply) during the 2010 period compared to the 2009 period.  Propylene fractionation volumes increased to 78 MBPD during the first nine months of 2010 from 67 MBPD during the first nine months of 2009.

Gross operating margin from octane enhancement was $35.6 million for the first nine months of 2010 compared to $4.1 million for the first nine months of 2009.  The $31.5 million period-to-period increase in gross operating margin is primarily due to higher sales volumes and margins from motor gasoline additives and revenues from by-product sales.  Octane enhancement production volumes were 14 MBPD during the first nine months of 2010 compared to 9 MBPD during the first nine months of 2009.  Production volumes for the 2009 period were negatively impacted by prolonged downtime for scheduled plant turnaround activities during the first quarter of 2009.

Gross operating margin from butane isomerization was $64.1 million for the first nine months of 2010 compared to $56.5 million for the first nine months of 2009, a $7.6 million period-to-period increase.  Higher commodity prices resulting in increased revenues from by-product sales more than offset the effect of lower isomerization volumes.  Butane isomerization volumes decreased to 89 MBPD during the first nine months of 2010 from 98 MBPD during the first nine months of 2009.

Gross operating margin from refined products pipelines and related activities was $130.8 million for the first nine months of 2010 compared to $78.2 million for the first nine months of 2009, a $52.6 million period-to-period increase.  Gross operating margin for the first nine months of 2009 includes a $28.7 million charge recognized by TEPPCO in the third quarter of 2009 in connection with its river terminal business.  Excluding this charge, gross operating margin increased $23.9 million period-to-period.  The expansion of our refined products marketing activities contributed $14.4 million of the period-to-period increase in gross operating margin.  In addition, our new refined products terminal in Port Arthur, Texas generated $4.0 million of gross operating margin for the first nine months of 2010.  Collectively, gross operating margin from the remainder of our refined products pipelines and related activities increased $5.5 million period-to-period primarily due to higher pipeline transportation fees.  Pipeline transportation volumes for the refined products business were 643 MBPD during the first nine months of 2010 compared to 674 MBPD during the first nine months of 2009.

Gross operating margin from marine transportation and other segment services was $50.0 million for the first nine months of 2010 compared to $48.0 million for the first nine months of 2009, a $2.0 million period-to-period increase.  An increase in gross operating margin attributable to earnings from recently acquired and constructed marine vessels was partially offset by higher operating expenses during the first nine months of 2010 as compared to the first nine months of 2009.

**Liquidity and Capital Resources**

At September 30, 2010, we had $42.7 million of unrestricted cash on hand and $1.8 billion of available credit under our revolving credit facilities, including the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners. Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business combinations and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) incl uding 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. It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities.

We had approximately $12.66 billion in principal outstanding under consolidated debt agreements at September 30, 2010. In May 2010, EPO issued an aggregate of $2.0 billion in principal amount of senior unsecured notes. EPO issued (i) $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes X") at 99.79% of their principal amount, (ii) $1.0 billion in principal amount of 10-year senior unsecured notes ("Senior Notes Y") at 99.701% of their principal amount and (iii) $600.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes Z") at 99.525% of their principal amount. Net proceeds from the issuance of these senior notes were used (i) to repay EPO's Senior Notes K in June 2010, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. EPO had borrowed $850.0 million under its Multi-Year Revolving Credit Facility to fund a portion of the cash consideration paid to complete the State Line and Fairplay acquisitions in May 2010. For additional information regarding our consolidated debt obligations, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

In June 2010, EPO entered into the Amended Acadian LLC Agreement with Duncan Energy Partners. This document includes the agreement between Duncan Energy Partners and EPO regarding funding arrangements for the Haynesville Extension. This expansion capital project will extend our south Louisiana intrastate natural gas pipeline system, which is owned by Acadian Gas, LLC, into northwest Louisiana and the Haynesville Shale production area. Duncan Energy Partners will fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures. The total expected cost of the Haynesville Extension project is approximately $1.56 billion (including capitalized interest), with Duncan Energy Partners' share currently estimated at $1.03 billion. In order to address its funding requirements under the Haynesville Extension project, Duncan Energy Partners entered into new senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

***Registration Statements***

We may issue equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. In July 2010, we filed a new universal shelf registration statement with the U.S. Securities and Exchange Commission ("SEC") that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. No securities have been issued under this registration statement as of the filing of this quarterly report.

The following tables present information regarding equity and debt offerings made under our prior universal shelf registration statement during 2010. Dollar amounts presented in the tables are in millions, except offering price amounts.

| Underwritten Equity Offering | Number of Common Units Issued | Offering Price | Total Net Cash Proceeds |
|---|---|---|---|
| January 2010 underwritten offering (1) | 10,925,000 | $ 32.42 | $ 350.3 |
| April 2010 underwritten offering (2) | 13,800,000 | $ 35.55 | 484.6 |
| Total | 24,725,000 | | $ 834.9 |

(1) Net cash proceeds from this equity offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.
(2) Net cash proceeds from this equity offering were used to pay a portion of the purchase price of the State Line and Fairplay natural gas gathering systems and for general partnership purposes.

| Note Series | Issued | Principal Amount |
|---|---|---|
| Senior Notes X, 3.70% fixed-rate, due June 2015 | May 2010 | $ 400.0 |
| Senior Notes Y, 5.20% fixed-rate, due September 2020 | May 2010 | 1,000.0 |
| Senior Notes Z, 6.45% fixed-rate, due September 2040 | May 2010 | 600.0 |
| Total | | $ 2,000.0 |

At September 30, 2010, Duncan Energy Partners could issue approximately $856.4 million of additional equity or debt securities under its universal shelf registration statement.

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate of 70,000,000 common units in connection with our distribution reinvestment plan ("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 nine months ended September 30, 2010, we issued 6,600,018 common units in connection with our DRIP, which generated proceeds of $213.8 million from plan participants. Affiliates of EPCO reinvested $169.6 million in connection with the DRIP during the nine months ended September 30, 2010.< /div>

In addition, we have a registration statement on file related to our employee unit purchase plan, under which we can issue up to an aggregate of 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the nine months ended September 30, 2010, we issued 140,634 common units to employees under this plan, which generated proceeds of $4.7 million.

For additional information regarding our partnership equity amounts, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

***Letter of Credit Facilities***

At September 30, 2010, EPO had a $50.0 million letter of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities.

***Credit Ratings***

At November 1, 2010, the investment-grade credit ratings of EPO's senior unsecured debt securities were: Baa3, Moody's Investor Services ("Moody's"); BBB-, Fitch Ratings; and BBB-, Standard and Poor's. In April 2010, Standard and Poor's reaffirmed its corporate credit rating of EPO, revised its outlook for EPO's business from "stable" to "positive" and updated its business risk assessment from "satisfactory" to "strong." EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that circumstances warrant such a change.  A credit rating from one rating agency should be evaluated independently of credit ratings from any other rating agencies.

Based on the debt and equity characteristics of EPO’s $1.53 billion of junior subordinated notes (a type of hybrid security), the rating agencies assigned partial equity treatment to such notes.  The ratings agencies use this treatment to adjust their credit metrics to gain a clearer economic view of the debt and equity components of our capitalization.  Standard and Poor’s assigns 50% equity treatment to the junior subordinated notes and Fitch Ratings assigns a 75% equity treatment.  In July 2010, Moody’s announced revisions to their classification system for hybrid securities.  Moody’s reduced the equity credit that it assigns to securities such as EPO’s junior subordinated notes from 50% to 25%.   We do not believe this revision will affect EPO’s investment-grade Baa3 senior unsecured debt rating from Moody’s.

A downgrade of EPO’s credit ratings could result in our being required to post financial collateral in connection with our guaranty of Centennial’s debt, which was $56.6 million at September 30, 2010.  Furthermore, from time to time we may enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if EPO’s credit ratings were to be downgraded below investment grade.

***Cash Flows from Operating, Investing and Financing Activities***

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions).  For information regarding the individual components of our cash flow amounts, see the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report on Form 10-Q.

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | **2010** | **2009** |
| Net cash flows provided by operating activities | $ 1,415.1 | $ 891.7 |
| Cash used in investing activities | 2,501.5 | 1,072.2 |
| Cash provided by financing activities | 1,074.1 | 196.5 |

Net cash flows provided by operating activities are largely dependent on earnings from our business activities.  As a result, these cash flows are exposed to certain risks.  We operate predominantly in the midstream energy industry.  We provide services for producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals.  The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstock in petrochemical manufacturing; and in the production of motor gasoline.  Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows.  For a more complete discussion of these and other risk factors pertinent to our business, see “Risk Factors” under Item 1A of our 2009 Form 10-K and also this quarterly report on Form 10-Q.

Our Unaudited Condensed Statements of Consolidated Cash Flows are prepared using the indirect method.  The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, operating lease expenses paid by EPCO, changes in the fair market value of derivative instruments and equity in earnings from unconsolidated affiliates (net cash flows provided by operating activities reflect the actual cash distributions we receive from such investees), and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.  In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Unaudited Condensed 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 period-to-period variances in our cash flow amounts:

***Comparison of Nine Months Ended September 30, 2010 with Nine Months Ended September 30, 2009***

*Operating Activities*. The $523.4 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates, cash payments for interest and cash payments for income taxes) increased $557.8 million period-to-period. The increase in operating cash flow is generally due to increased profitability (e.g., our gross operating margin increased $456.0 million period-to-period) and the timing of related cash receipts and disbursements.

§ Distributions received from unconsolidated affiliates increased $27.1 million period-to-period primarily due to higher distributions received from Poseidon and K/D/S Promix, L.L.C. In February 2010, we also began receiving distributions from Skelly-Belvieu Pipeline Company, L.L.C.

§ Cash payments for interest increased approximately $75.5 million period-to-period primarily due to an increase in fixed-rate debt obligations.

§ Cash payments for income taxes decreased $14.0 million period-to-period primarily due to higher payments made during the nine months ended September 30, 2009 attributable to the Texas Margin Tax and a taxable gain arising from Dixie's sale of certain assets.

*Investing Activities*. The $1.43 billion increase in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations increased $1.16 billion period-to-period, primarily due to the May 2010 acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion.

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $303.6 million period-to-period. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 2.

§ Cash inflows related to restricted cash decreased $62.9 million period-to-period primarily due to reductions in the margin requirements of our commodity hedging positions.

§ Proceeds from asset sales and related transactions increased $86.7 million period-to-period primarily due to insurance proceeds received during the third quarter 2010 related to the disposition of assets.

*Financing Activities*. The $877.6 million increase in cash provided by financing activities was primarily due to the following:

- § Net borrowings under our consolidated debt agreements increased $980.2 million period-to-period. During the nine months ended September 30, 2010, EPO issued $2.0 billion in senior notes (Senior Notes X, Y and Z) offset by (i) the repayment of its $500.0 million of Senior Notes K and $54.0 million Pascagoula Mississippi Business Finance Corporation ("MBFC") Loan and (ii) the temporary repayment of a portion of amounts borrowed under its Multi-Year Revolving Credit Facility. For additional information regarding our consolidated debt obligations see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

- § Cash distributions paid to our partners increased $403.0 million period-to-period due to increases in our common units outstanding and quarterly distribution rates.

- § Cash distributions paid to noncontrolling interests decreased $268.3 million period-to-period primarily due to the cessation of cash distributions to the former owners of TEPPCO in connection with the TEPPCO Merger.

- § Cash contributions from noncontrolling interests decreased $135.9 million period-to-period primarily due to Duncan Energy Partner's issuance of its common units in June and July 2009, which generated $137.4 million in proceeds.

- § Net cash proceeds from the issuance of our common units increased $180.3 million period-to-period primarily due to an increase in the prices of our common units in connection with equity offerings in January and April 2010 compared to those in January and September 2009.

***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 in the Rocky Mountains, Northeast and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale and Eagle Ford Shale producing regions.

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

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

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | **2010** | **2009** |
| Capital spending for property, plant and equipment, net of contributions in aid of construction costs | $ 1,391.2 | $ 1,087.6 |
| Capital spending for business combinations | 1,233.0 | 74.5 |
| Capital spending for intangible assets | -- | 1.4 |
| Capital spending for investments in unconsolidated affiliates | 6.3 | 13.9 |
| Total capital spending | $ 2,630.5 | $ 1,177.4 |

Capital spending for business combinations for the nine months ended September 30, 2010 reflects the $1.2 billion we spent to acquire the State Line and Fairplay natural gas gathering systems in

May 2010.  For additional information regarding our business combinations, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2010 will be approximately $870 million, which includes estimated expenditures of $800 million for growth capital projects and acquisitions and $70 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our currently 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 September 30, 2010, we had approximately $927.9 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment.  These commitments primarily relate to construction at our Mont Belvieu complex and our Barnett Shale, Eagle Ford Shale, Haynesville Shale and Piceance Basin natural gas pipeline projects.

***Pipeline Integrity Costs***

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

The following table summarizes our pipeline integrity costs for the periods indicated (dollars in millions):

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2010** | **2009** | **2010** | **2009** |
| Expensed | $ 9.5 | $ 11.8 | $ 28.9 | $ 33.4 |
| Capitalized | 14.7 | 11.3 | 28.2 | 26.6 |
| Total | $ 24.2 | $ 23.1 | $ 57.1 | $ 60.0 |

We expect the costs of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $29.7 million for the remainder of 2010.

**Critical Accounting Policies and Estimates**

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our 2009 Form 10-K.  Certain of these accounting policies require the use of estimates.  As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis:

depreciation methods and estimated useful lives of property, plant and equipment; measuring recoverability of long-lived assets and equity method investments; amortization methods and estimated useful lives of qualifying intangible assets; methods we employ to measure the fair value of goodwill; revenue recognition policies and use of estimates for revenues and expenses; reserves for environmental matters and litigation contingencies; and natural gas imbalances. These estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may change as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows .

**Other Items**

***Recent Accounting Developments***

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). IFRS consist of accounting standards published by the International Accounting Standards Board ("IASB"), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently, the Financial Accounting Standards Board (or "FASB," based in Norwalk, Connecticut) and the IASB are working both individually and jo intly on a number of accounting standard convergence projects that, if finalized in 2011, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, financial instruments, consolidations and fair value measurements.

The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS, with the expectation that any decision to adopt IFRS will allow U.S. issuers a number of years to transition from current U.S. GAAP. We continue to monitor developments regarding the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

***Insurance Matters***

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. During the three months ended September 30, 2010, we recognized net gains of approximately $56.6 million related to insurance recoveries associated with an offshore natural gas pipeline system and an offshore platform. The proceeds approximate the negotiated insurance value of the covered assets, which were damaged by windstorms or other events. For additional information regarding insurance matters, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

***Contractual Obligations***

With the exception of (i) routine fluctuations in the balance of our consolidated revolving credit facilities, (ii) the issuance of Senior Notes X, Y and Z in May 2010 and (iii) the repayments of the Pascagoula MBFC Loan in March 2010 and Senior Notes K in June 2010, there have been no significant changes in our consolidated debt obligations since those reported in our 2009 Form 10-K. For additional information regarding our consolidated debt obligations, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

***Off-Balance Sheet Arrangements***

There have been no significant changes with regards to our off-balance sheet arrangements since those reported in our 2009 Form 10-K.

***Related Party Transactions***

Historically, EPCO has provided us with tank truck services for the transportation of NGLs and other products. In September 2010, we acquired EPCO's ownership interests in its trucking business, or Enterprise Transportation Company ("ETC"), in exchange for 523,306 of our common units. Since we and EPCO are under common control, we recorded the net assets of ETC based on EPCO's historical basis of $30.6 million. The equity consideration we issued was based on the average closing price of our common units over a 20-day period ending September 28, 2010. For additional information regarding our related party transactions, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

***Regulatory Matters***

Certain scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide (which is a component of, and a product of combustion of, natural gas) and methane (which is a component of natural gas), may be contributing to global climate change and ocean acidification. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA") which, if it were to become law, would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases by the United States and would require most significant domestic sources of greenhouse gas emissions to obtain greenhouse gas emiss ion "allowances" corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun consideration of various legislative proposals for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency ("EPA") announced its finding that emissions of greenhouse gases from motor vehicles caused or contributed to climate change and presented an endangerment to human health and the environment. These findings by the EPA were the basis for motor vehicle greenhouse gas emissions standards promulgated on May 7, 2010, and may allow the agency to proceed with the adoption and implementation of additional regulations that would require permits or control emissions of greenhouse gases from industrial sources under existing provisions of the federal Clean Air Act. On May 13, 2010, the EPA issued a final rule setting forth a timetable for its Tit le V and Prevention of Significant Deterioration regulatory program, applicable in certain circumstances to new and modified industrial source of air emissions, to include consideration of greenhouse gas emissions. The EPA has also received petitions requesting that the agency further expand regulation of greenhouse gas emissions from industrial sources, which, over time, may lead to additional requirements. On April 12, 2010, the EPA proposed new rules that would require the mandatory reporting of greenhouse gas emissions by operators of natural gas compression, processing and storage facilities. These rules supplement disclosures and reporting required by the EPA in its October 30, 2009 mandatory greenhouse gas reporting rule. These and any new laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases, or that establish new reporting requirements, will require us to incur increased operating costs, and may have an adverse effect on our financial position, results of operations and cash flows.

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***Non-GAAP Reconciliations***

The following table presents a reconciliation of our non-GAAP measure of total segment gross operating margin to GAAP operating income and income before provision for income taxes for the periods indicated (dollars in millions):

| | For the Three Months Ended September 30, 2010 | For the Three Months Ended September 30, 2009 | For the Nine Months Ended September 30, 2010 | For the Nine Months Ended September 30, 2009 |
|---|---|---|---|---|
| Total segment gross operating margin | $ 820.8 | $ 638.7 | $ 2,430.9 | $ 1,974.9 |
| Adjustments to reconcile total segment gross operating margin to operating income: | | | | |
| Depreciation, amortization and accretion in operating costs and expenses | (235.1) | (206.0) | (674.5) | (602.9) |
| Non-cash asset impairment charges | -- | (24.0) | (1.5) | (26.3) |
| Operating lease expenses paid by EPCO | (0.2) | (0.2) | (0.5) | (0.5) |
| Gains from asset sales and related transactions in operating costs and expenses | 39.7 | 0.1 | 45.3 | 0.5 |
| General and administrative costs | (56.0) | (52.3) | (131.5) | (133.3) |
| Operating income | 569.2 | 356.3 | 1,668.2 | 1,212.4 |
| Other expense, net | (178.4) | (160.8) | (495.1) | (469.8) |
| Income before provision for income taxes | $ 390.8 | $ 195.5 | $ 1,173.1 | $ 742.6 |

**Item 3.** ***Quantitative and Qualitative Disclosures about Market Risk.***

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain anticipated transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities. See Note 4 of the Notes to the Unaudited Condensed Financial Statements included under Item 1 of this quarterly report for additional information regarding our derivative instruments and hedging activities.

Our exposures to market risk have not changed materially since those reported under Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2009 Form 10-K.

***Interest Rate Derivative Instruments***

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following tables show the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolios at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Swap Fair Value at September 30, 2010 | Swap Fair Value at October 19, 2010 |
|---|---|---|---|
| FV assuming no change in underlying interest rates | *Asset* | $ 68.1 | $ 64.7 |
| FV assuming 10% increase in underlying interest rates | *Asset* | 66.1 | 62.9 |
| FV assuming 10% decrease in underlying interest rates | *Asset* | 70.2 | 66.4 |

The following table shows the effect of hypothetical price movements on the estimated fair value of our forward starting swap portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Swap Fair Value at September 30, 2010 | Swap Fair Value at October 19, 2010 |
|---|---|---|---|
| FV assuming no change in underlying commodity prices | *Liability* | $ (122.1) | $ (121.4) |
| FV assuming 10% increase in underlying commodity prices | *Liability* | (70.1) | (69.4) |
| FV assuming 10% decrease in underlying commodity prices | *Liability* | (176.2) | (175.3) |

***Commodity Derivative Instruments***

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. We may use commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contacts to mitigate such risks.

We assess the risk of our commodity derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to these portfolios measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity derivative instruments outstanding at the date indicated within the following tables.

The following table shows the effect of hypothetical price movements on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Portfolio Fair Value at September 30, 2010 | Portfolio Fair Value at October 19, 2010 |
|---|---|---|---|
| FV assuming no change in underlying commodity prices | *Asset* | $ 3.7 | $ 13.2 |
| FV assuming 10% increase in underlying commodity prices | *Asset (Liability)* | (6.9) | 2.7 |
| FV assuming 10% decrease in underlying commodity prices | *Asset* | 14.4 | 23.8 |

The following table shows the effect of hypothetical price movements on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Portfolio Fair Value at September 30, 2010 | Portfolio Fair Value at October 19, 2010 |
|---|---|---|---|
| FV assuming no change in underlying commodity prices | *Liability* | $ (31.6) | $ (20.1) |
| FV assuming 10% increase in underlying commodity prices | *Liability* | (78.8) | (61.1) |
| FV assuming 10% decrease in underlying commodity prices | *Asset* | 15.5 | 20.9 |

The following table shows the effect of hypothetical price movements on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Portfolio Fair Value at September 30, 2010 | Portfolio Fair Value at October 19, 2010 |
|---|---|---|---|
| FV assuming no change in underlying commodity prices | *Liability* | $ (5.4) | $ (4.1) |
| FV assuming 10% increase in underlying commodity prices | *Liability* | (20.4) | (18.4) |
| FV assuming 10% decrease in underlying commodity prices | *Asset* | 9.7 | 10.1 |

Our predominant hedging strategy is to hedge an amount of gross margin associated with our gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of:

- § the forward sale of a portion of our expected equity NGL production at fixed prices through June 2011, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and

- § the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At September 30, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $152.4 million on 6.4 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through June 2011. At October 21, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $292.2 million on 10.1 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through June 2011. Our estimates of future gross margins are subject to various business risks, including unforeseen production outages or declines, counterparty risk, or similar events or developments that are outside of our control.

***Foreign Currency Derivative Instruments***

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency values between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in an exchange rate. At September 30, 2010, our foreign currency derivative instruments portfolio had a notional amount of $7.0 million Canadian. The fair market value of these derivative instruments was an asset of $0.1 million at September 30, 2010.

## Item 4. *Controls and Procedures*.

**Disclosure Controls and Procedures**

As of the end of the period covered by this quarterly report, our management carried out an evaluation, with the participation of our general partner's CEO (our principal executive officer) and our general partner's chief financial officer (our principal financial officer) (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this report, the CEO and CFO concluded:

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

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

**Changes in Internal Control over Financial Reporting**

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the third quarter of 2010, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this quarterly report.

## PART II.  OTHER INFORMATION

**Item 1.  *Legal Proceedings*.**

For information regarding legal proceedings, see Part I, Item 1, Financial Statements, Note 15, "Commitments and Contingencies – Litigation," of the Notes to Unaudited Condensed Consolidated Financial Statements included in this quarterly report, which is incorporated herein by reference.

**Item 1A.  *Risk Factors*.**

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2009 annual report on Form 10-K and below, in addition to other information in such annual report and in this quarterly report on Form 10-Q.  We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

***Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays incurred by customers in the production of oil and natural gas, including from the developing shale plays.  A decline in drilling of new wells and related servicing activities caused by these initiatives could adversely affect our financial position, results of operations and cash flows.***

Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act, or other authority.  Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale, coal bed and tight sand formations.  Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts.   ;The Chairman of the House Energy and Commerce Committee has initiated an investigation of the potential impacts of hydraulic fracturing, which has involved seeking information about fracturing activities and chemicals from certain companies in the oil and gas sector.  In addition, in March 2010, the U.S. EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health.  The EPA has begun preparation for the study and expects to complete the study in 2012.  In addition, various state-level initiatives in regions with substantial shale gas supplies have been proposed or implemented to regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, or protect drinking water supplies.  Moreover, public debate over hydraulic fracturing and shale gas production has been increasing, and has resulted i n delays of well permits in some areas, particularly in the Marcellus Shale play.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques.  Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing.  If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, our profitability could be materially impacted.

***Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows.***

On April 20, 2010, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill. As a result, on May 28, 2010, the U.S. Department of the Interior issued a six-month moratorium that halted drilling of uncompleted and new oil and gas wells (in water deeper than 500 feet) in the Gulf of Mexico with certain limited exceptions and halted consideration of drilling permits for deepwater wells. In addition to the moratorium, the Department of the Interior also canceled or delayed offshore oil and gas lease sales off the Mid-Atlantic coast and in Alaska. Under political and legal pressure, the Interior Secretary withdrew the moratorium and replaced it on July 12, 2010 with a suspension of certain offshore dril ling activities that was to be effective through October 30, 2010.

The drilling suspension was lifted by the Interior Secretary on October 12, 2010. However, the timing and process for approving applications for new permits to drill and the cost associated with compliance with various new and enhanced safety and environmental requirements imposed following the Deepwater Horizon incident (discussed below) remain uncertain.

Following the Deepwater Horizon event, the Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”), formerly the Minerals Management Service, an office of the Department of the Interior which is charged with oversight of the United States’ oil, natural gas and other minerals on the Outer Continental Shelf, is being reorganized under a secretarial order of the Department of Interior, which may be reinforced through legislation. Since the Deepwater Horizon event, the Department of the Interior, through the BOEMRE, has issued a series of rules that increase regulatory requirements for offshore oil and gas operations. On June 8, 2010, the BOEMRE issued a notice to holders of offshore oil and gas leases requiring compliance certificatio ns and third party verification of certain inspection and design matters. On June 18, 2010, a subsequent notice to lessees called for enhanced information regarding planning scenarios relating to blowouts, discharges of pollutants and prevention of accidents. Another notice to lessees on August 16, 2010, made changes to the environmental review process for offshore oil and gas development. On October 14, 2010, the BOEMRE published an emergency drilling safety rule imposing additional requirements for well bore integrity and well control equipment and procedures, including provisions addressing blowout preventers and the use of drilling fluids. This interim final rule became effective immediately, but is subject to future changes that may be made by the BOEMRE in response to public comments received by December 13, 2010. On October 15, 2010, the BOEMRE also published a final rule requiring safety and environmental management systems for all oil and gas operations on the Outer Continental Shelf. The Interior Secretary has stated that companies with offshore operations will face a “dynamic regulatory environment” following the end of the moratorium and suspension. Moreover, understaffing at the Department of the Interior and reorganization of the BOEMRE may further delay the processing of permits. In addition to federal regulatory activity, at least one state has ordered enhanced inspections of oil and gas rigs and required more stringent disaster preparedness plans, and it is possible that other state-level requirements will be imposed on offshore energy production activities.

Accordingly, the effect of new regulatory requirements on offshore energy development in the Gulf of Mexico, including the prospects and timing of securing permits for offshore energy production activities, are evolving and uncertain. Such uncertainty may cause companies to curtail or delay oil and gas production activities, or to redirect resources to other areas such as West Africa, the Caribbean or South America, which may further delay the resumption of drilling activity in the Gulf of Mexico. It is uncertain at this time how and to what extent oil and natural gas supplies from the Gulf of Mexico and other offshore drilling areas will be affected.

In addition to federal agency action, numerous legislative proposals have been introduced in the U.S. Congress in reaction to the Deepwater Horizon incident, some of which may be considered during the remainder of the current legislative session, and similar measures may be introduced in subsequent legislative periods. Bills that have received attention include measures to:

- modify or revoke liability limits and caps under the Oil Spill Liability Trust Fund, the Oil Pollution Act of 1990, and certain other statutes;
- revise federal liability regimes to include health effects, personal injuries, and other tort claims;
- mandate more stringent safety measures and inspections under the Oil Pollution Act and Outer Continental Shelf Lands Act;
- expand environmental reviews and lengthen review timelines;
- impose fees, increase taxes or remove tax exemptions;
- modify financial responsibility and insurance requirements for offshore energy activities; and
- require U.S. registration of oil rigs.

However, it is unclear and cannot be predicted whether and when Congress may pass legislation.

Given the scope and effect of the Deepwater Horizon incident, as well as statements made by the Interior Secretary, it is expected that additional regulatory compliance and agency reviews will be required prior to permitting new wells or continued drilling of existing wells, which may affect the cost and timing of oil and gas production in the Gulf of Mexico and other offshore areas. A decline in, or failure to achieve anticipated volumes of, oil and natural gas supplies due to any of the foregoing factors may have a material adverse effect on our financial position, results of operations or cash flows through reduced gathering and transportation volumes, processing activities, or other midstream services.

***The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.***

The United States Congress has passed, and the President has signed into law, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”). The Act provides for new statutory and regulatory requirements for financial derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. The Act requires th e Commodity Futures Trading Commission (the “CFTC”) to promulgate rules to define these terms in detail, but we do not know the definitions that the CFTC will actually promulgate or how these definitions will apply to us.

The majority of our financial derivative transactions are currently executed and cleared over exchanges that already require the posting of cash collateral or letters of credit based on initial and variation margin requirements. We enter into over-the-counter natural gas, NGL, crude oil and refined products derivative contracts from time to time with respect to a portion of our expected processing, storage and transportation activities in order to hedge against commodity price uncertainty and enhance the predictability of cash flows from these activities. Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide additional cash collateral for our commodities hedging transactions whether cleared over an exchange or new cash collateral for those transactions executed over-the-counter. Posting of additional or new cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post additional or new cash collateral could therefore significantly reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk unless and until the CFTC adopts rules and definitions that confirm that companies such as ourselves are not required to post cash collateral for our over-the-counter derivative hedging contracts nor increase the amount of cash collateral posted for transactions cleared over an exchange. In addition, even if we ourselves are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Act's new requirements. These requirements may affect the liquidity and pricing of derivative contracts, and the costs of compliance by dealers and counterparties will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

**Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds.***

As of September 30, 2010, we and our affiliates could repurchase up to 618,400 additional common units under the December 1998 Common Unit Repurchase Program. We did not repurchase any of our common units in connection with this program during the nine months ended September 30, 2010.

The following table summarizes our repurchase activity during 2010 in connection with other arrangements:

| Period | Total Number of Units Purchased | Average Price Paid per Unit | Total Number of Units Purchased as Part of Publicly Announced Plans | Maximum Number of Units That May Yet Be Purchased Under the Plans |
|---|---|---|---|---|
| February 2010 (1) | 7,480 | $32.17 | -- | -- |
| May 2010 (2) | 78,522 | $35.60 | -- | -- |
| August 2010 (3) | 2,621 | $37.74 | -- | -- |

(1) Of the 34,528 restricted units that vested in February 2010 and converted to common units, 7,480 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 287,700 restricted units that vested in May 2010 and converted to common units, 78,522 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 17,400 restricted units that vested in August 2010 and converted to common units, 2,621 units were sold back to us by employees to cover related withholding tax requirements.

On September 30, 2010, we issued 523,306 of our unregistered common units to EPCO in exchange for all of EPCO's ownership interest in ETC. The equity consideration we issued was based on the average closing price of our common units over a 20-day period ending September 28, 2010. Because the issuance was to an affiliate and did not involve any public offering, the issuance of these common units was exempt from registration by Section 4(2) of the Securities Act of 1933, as amended.

**Item 3. *Defaults upon Senior Securities.***

None.

**Item 4. *(Removed and Reserved).***

**Item 5. *Other Information.***

None.

**Item 6. *Exhibits.***

| Exhibit Number | Exhibit* |
|---|---|
| 2.1 | Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010). |

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| 2.2 | Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010). |
| 2.3 | Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010). |
| 2.4 | Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003). |
| 2.5 | Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004). |
| 2.6 | Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003). |
| 2.7 | Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004). |
| 2.8 | Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003). |
| 2.9 | Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009). |
| 2.10 | Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009). |
| 3.1 | Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007). |
| 3.2 | Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005). |
| 3.3 | Amendment No. 1 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008). |
| 3.4 | Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008). |
| 3.5 | Amendment No. 3 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.5 to Form 10-Q filed November 10, 2008). |
| 3.6 | Amendment No. 4 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated October 26, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 28, 2009). |

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| 3.7 | Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 9, 2007). |
| 3.8 | First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 3.7 to Form 10-Q filed November 10, 2008). |
| 3.9 | Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007). |
| 3.10 | Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004). |
| 3.11 | Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004). |
| 4.1 | Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Form S-1A Registration Statement, Reg. No. 333-52537, filed July 21, 1998). |
| 4.2 | Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000). |
| 4.3 | First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.4 | Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003). |
| 4.5 | Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007). |
| 4.6 | Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004). |
| 4.7 | First Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 6, 2004). |
| 4.8 | Second Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 6, 2004). |
| 4.9 | Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004). |
| 4.10 | Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004). |
| 4.11 | Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005). |

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| 4.12 | Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005). |
| 4.13 | Seventh Supplemental Indenture, dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005). |
| 4.14 | Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006). |
| 4.15 | Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007). |
| 4.16 | Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007). |
| 4.17 | Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007). |
| 4.18 | Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008). |
| 4.19 | Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008). |
| 4.20 | Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008). |
| 4.21 | Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009). |
| 4.22 | Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009). |
| 4.23 | Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009). |
| 4.24 | Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009). |
| 4.25 | Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed May 20, 2010). |

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| 4.26 | Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.27 | Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003). |
| 4.28 | Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001). |
| 4.29 | Global Note representing $500.0 million principal amount of 4.00% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.30 | Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.31 | Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.32 | Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.33 | Global Note representing $500.0 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K filed March 15, 2005). |
| 4.34 | Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005). |
| 4.35 | Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005). |
| 4.36 | Global Note representing $500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005). |
| 4.37 | Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006). |
| 4.38 | Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007). |
| 4.39 | Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008). |
| 4.40 | Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008). |
| 4.41 | Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008). |
| 4.42 | Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009). |
| 4.43 | Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009). |
| 4.44 | Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009). |

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| 4.45 | Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009). |
| 4.46 | Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009). |
| 4.47 | Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009). |
| 4.48 | Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009). |
| 4.49 | Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009). |
| 4.50 | Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009). |
| 4.51 | Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010). |
| 4.52 | Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010). |
| 4.53 | Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010). |
| 4.54 | Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007). |
| 4.55 | First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006). |
| 4.56 | Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009). |
| 4.57 | Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002). |
| 4.58 | First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002). |
| 4.59 | Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002). |

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| 4.60 | Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003). |
| 4.61 | Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006). |
| 4.62 | Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007). |
| 4.63 | Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008). |
| 4.64 | Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008). |
| 4.65 | Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008). |
| 4.66 | Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009). |
| 4.67 | Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010). |
| 4.68 | Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007). |
| 4.69 | First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007). |
| 4.70 | Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007). |
| 4.71 | Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007). |

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| 4.72 | Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009). |
| 4.73 | Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010). |
| 10.1*** | Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed August 9, 2010). |
| 10.2*** | Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed August 9, 2010). |
| 10.3*** | Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed August 9, 2010). |
| 10.4*** | Amendment to Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed August 9, 2010). |
| 10.5*** | Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 10-Q filed August 9, 2010). |
| 10.6*** | Form of Option Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010). |
| 10.7*** | Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010). |
| 10.8*** | Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010). |
| 10.9*** | Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.9 to Form 10-Q filed August 9, 2010). |
| 10.10*** | Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.10 to Form 10-Q filed August 9, 2010). |
| 10.11*** | Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 10-Q filed August 9, 2010). |
| 10.12*** | Amendment to Form of Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.12 to Form 10-Q filed August 9, 2010). |
| 10.13*** | Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Form 10-Q filed August 9, 2010). |
| 10.14*** | Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.14 to Form 10-Q filed by Duncan Energy Partners L.P. on August 9, 2010). |
| 10.15*** | Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.15 to Form 10-Q filed by Duncan Energy Partners L.P. on August 9, 2010). |

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| 10.16 | First Amendment to Loan Agreement, dated August 20, 2010, between Enterprise Products Operating LLC, as lender, and Duncan Energy Partners L.P., as borrower (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on August 23, 2010). |
| 10.17 | Support Agreement, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., DD Securities LLC, DFI GP Holdings, L.P., EPCO Holdings, Inc., Duncan Family Interests, Inc., Dan Duncan LLC and DFI Delaware Holdings L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 7, 2010). |
| 10.18*** | Retention Agreement between William Ordemann and Enterprise Products Company dated effective October 1, 2010 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 14, 2010). |
| 10.19 | First Amendment to Amended and Restated Revolving Credit Agreement, dated as of October 22, 2010, by and among Enterprise Products Operating LLC, as Borrower, Wells Fargo Bank, National Association, successor-by-merger to Wachovia Bank, National Association, as Administrative Agent, and the Lenders Party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 26, 2010). |
| 10.20 | Second Amendment to Term Loan Agreement, dated October 25, 2010, among Duncan Energy Partners L.P., as borrower, Wells Fargo Bank, National Association, successor-by-merger to Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on October 26, 2010). |
| 10.21 | Revolving Credit and Term Loan Agreement, dated October 25, 2010, among Duncan Energy Partners L.P., as borrower, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB NOR Bank ASA and the Royal Bank of Scotland, plc, as Co-Syndication Agents, and Scotia Capital, Barclays Bank plc and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Duncan Energy Partners L.P. on October 26, 2010). |
| 31.1# | Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2010 quarterly report on Form 10-Q. |
| 31.2# | Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the September 30, 2010 quarterly report on Form 10-Q. |
| 32.1# | Section 1350 certification of Michael A. Creel for the September 30, 2010 quarterly report on Form 10-Q. |
| 32.2# | Section 1350 certification of W. Randall Fowler for the September 30, 2010 quarterly report on Form 10-Q. |
| 101.CAL# | XBRL Calculation Linkbase Document |
| 101.DEF# | XBRL Definition Linkbase Document |
| 101.INS# | XBRL Instance Document |
| 101.LAB# | XBRL Labels Linkbase Document |
| 101.PRE# | XBRL Presentation Linkbase Document |
| 101.SCH# | XBRL Schema Document |

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| * | With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise GP Holdings L.P, Duncan Energy Partners L.P., TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-32610, 1-33266, 1-10403 and 1-13603, respectively. |
| *** | Identifies management contract and compensatory plan arrangements. |
| # | Filed with this report. |

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on November 9, 2010.

**ENTERPRISE PRODUCTS PARTNERS L.P.**
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC, as General Partner

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| By: | /s/ Michael J. Knesek |
| Name: | Michael J. Knesek |
| Title: | Senior Vice President, Controller<br>and Principal Accounting Officer<br>of the General Partner |

**EXHIBIT 31.1**

**CERTIFICATIONS**

I, Michael A. Creel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2010

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P.

**EXHIBIT 31.2**

**CERTIFICATIONS**

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2010

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products GP, LLC,
the General Partner of Enterprise Products Partners L.P.

**SARBANES-OXLEY SECTION 906 CERTIFICATION**

**CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER
OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF
ENTERPRISE PRODUCTS PARTNERS L.P.**

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel

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| Name: | Michael A. Creel |
| Title: | Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P. |

Date: November 9, 2010

**EXHIBIT 32.2**

**SARBANES-OXLEY SECTION 906 CERTIFICATION**

**CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.**

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

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| Name: | W. Randall Fowler |
| Title: | Chief Financial Officer of Enterprise Products GP, LLC<br>the General Partner of Enterprise Products Partners L.P. |

Date: November 9, 2010