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 March 31, 2011

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

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

Yes o No ☑

There were 845,386,852 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 April 30, 2011. 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	March 31, 2011	December 31, 2010
Current assets:		
Cash and cash equivalents	$ 150.4	$ 65.5
Restricted cash	191.6	98.7
Accounts receivable – trade, net of allowance for doubtful accounts of $13.5 at March 31, 2011 and $18.4 at December 31, 2010	3,881.3	3,800.1
Accounts receivable – related parties	31.0	36.8
Inventories	800.8	1,134.0
Prepaid and other current assets	391.7	372.0
Total current assets	5,446.8	5,507.1
Property, plant and equipment, net	19,892.9	19,332.9
Investments in unconsolidated affiliates	2,269.9	2,293.1
Intangible assets, net of accumulated amortization of $945.3 at March 31, 2011 and $932.3 at December 31, 2010	1,794.0	1,841.7
Goodwill	2,107.7	2,107.7
Other assets	309.9	278.3
Total assets	$ 31,821.2	$ 31,360.8
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt	$ 782.3	$ 282.3
Accounts payable – trade	607.6	542.0
Accounts payable – related parties	139.0	133.1
Accrued product payables	4,078.7	4,164.8
Accrued interest	181.3	252.9
Other current liabilities	669.2	505.1
Total current liabilities	6,458.1	5,880.2
Long-term debt: (see Note 9)	13,273.6	13,281.2
Deferred tax liabilities	78.6	78.0
Other long-term liabilities	210.9	220.6
Commitments and contingencies		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (845,431,409 units outstanding at March 31, 2011 and 843,681,572 units outstanding at December 31, 2010)	11,258.5	11,288.2
Class B units (4,520,431 units outstanding at March 31, 2011 and December 31, 2010)	118.5	118.5
Accumulated other comprehensive loss	(100.1)	(32.5)
Total partners' equity	11,276.9	11,374.2
Noncontrolling interest	523.1	526.6
Total equity	11,800.0	11,900.8
Total liabilities and equity	$ 31,821.2	$ 31,360.8

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 March 31,	
	2011	**2010**
Revenues:		
Third parties	$ 9,933.6	$ 8,312.1
Related parties	250.1	232.4
Total revenues (see Note 11)	10,183.7	8,544.5
Costs and expenses:		
Operating costs and expenses:		
Third parties	9,111.5	7,647.9
Related parties	425.6	324.0
Total operating costs and expenses	9,537.1	7,971.9
General and administrative costs:		
Third parties	12.9	16.3
Related parties	25.0	24.0
Total general and administrative costs	37.9	40.3
Total costs and expenses (see Note 11)	9,575.0	8,012.2
Equity in income of unconsolidated affiliates	16.2	26.6
Operating income	624.9	558.9
Other income (expense):		
Interest expense	(183.8)	(157.9)
Interest income	0.3	0.2
Other, net	0.2	(0.1)
Total other expense, net	(183.3)	(157.8)
Income before provision for income taxes	441.6	401.1
Provision for income taxes	(7.1)	(8.7)
Net income	434.5	392.4
Net income attributable to noncontrolling interest (see Note 10)	(13.8)	(322.5)
Net income attributable to partners	$ 420.7	$ 69.9
Allocation of net income attributable to partners:		
Limited partners	$ 420.7	$ 69.9
General partner	$ --	$ **
Earnings per unit (see Note 13)		
Basic earnings per unit	$ 0.52	$ 0.33
Diluted earnings per unit	$ 0.49	$ 0.33

See Notes to Unaudited Condensed Consolidated Financial Statements.
** Amount is negligible.

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

	For the Three Months Ended March 31,	
	2011	**2010**
Net income	$ 434.5	$ 392.4
Other comprehensive income (loss):		
Cash flow hedges:		
Commodity derivative instrument losses during period	(151.4)	(58.9)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	68.9	16.5
Interest rate derivative instrument gains (losses) during period	14.1	(7.5)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	1.5	6.1
Foreign currency derivative losses during period	--	(0.1)
Reclassification adjustment for gains included in net income related to foreign currency derivative instruments	--	(0.3)
Total cash flow hedges	(66.9)	(44.2)
Foreign currency translation adjustment	--	0.6
Change in funded status of pension and postretirement plans, net of tax	0.3	(0.9)
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	(1.0)	1.0
Total other comprehensive loss	(67.6)	(43.5)
Comprehensive income	366.9	348.9
Comprehensive income attributable to noncontrolling interest	(13.8)	(279.5)
Comprehensive income attributable to partners	$ 353.1	$ 69.4

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 Three Months Ended March 31, 2011	2010
Operating activities:		
Net income	$ 434.5	$ 392.4
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	241.1	218.6
Non-cash asset impairment charges	--	1.5
Equity in income of unconsolidated affiliates	(16.2)	(26.6)
Distributions received from unconsolidated affiliates	42.5	51.4
Operating lease expenses paid by EPCO	0.2	0.2
Gains from asset sales and related transactions	(18.4)	(7.5)
Deferred income tax expense	0.8	1.0
Changes in fair market value of derivative instruments	(1.3)	(7.8)
Effect of pension settlement recognition	(0.5)	(0.2)
Net effect of changes in operating accounts (see Note 16)	120.0	73.4
Net cash flows provided by operating activities	802.7	696.4
Investing activities:		
Capital expenditures	(713.5)	(347.8)
Contributions in aid of construction costs	3.2	3.6
Increase in restricted cash	(92.9)	(38.1)
Cash used for business combinations	--	(2.2)
Investments in unconsolidated affiliates	(3.8)	(7.7)
Proceeds from asset sales and related transactions	84.2	21.7
Other investing activities	(3.6)	--
Cash used in investing activities	(726.4)	(370.5)
Financing activities:		
Borrowings under debt agreements	2,821.6	378.1
Repayments of debt	(2,316.0)	(615.8)
Debt issuance costs	(12.8)	(0.1)
Cash distributions paid to partners	(479.7)	(73.8)
Cash distributions paid to noncontrolling interest	(17.2)	(351.9)
Cash contributions from noncontrolling interest	1.3	417.3
Net cash proceeds from issuance of common units	21.0	--
Acquisition of treasury units	(3.9)	(0.2)
Other financing activities	(5.7)	--
Cash provided by (used in) financing activities	8.6	(246.4)
Effect of exchange rate changes on cash	--	0.4
Net change in cash and cash equivalents	84.9	79.5
Cash and cash equivalents, January 1	65.5	55.3
Cash and cash equivalents, March 31	$ 150.4	$ 135.2

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 10 for Unit History, Accumulated Other Comprehensive Loss and Noncontrolling Interest)
(Dollars in millions)

	Partners' Equity				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2010	$ 11,406.7	$ --	$ (32.5)	$ 526.6	$ 11,900.8
Net income	420.7	--	--	13.8	434.5
Operating lease expenses paid by EPCO	0.2	--	--	--	0.2
Cash distributions paid to partners	(479.7)	--	--	--	(479.7)
Cash distributions paid to noncontrolling interest	--	--	--	(17.2)	(17.2)
Cash contributions from noncontrolling interest	--	--	--	1.3	1.3
Net cash proceeds from issuance of common units	21.0	--	--	--	21.0
Acquisition of treasury units	(3.9)	--	--	--	(3.9)
Amortization of equity awards	12.0	--	--	0.1	12.1
Change in value of cash flow hedges	--	--	(66.9)	--	(66.9)
Proportionate share of other comprehensive loss of unconsolidated affiliate	--	--	(1.0)	--	(1.0)
Other	--	--	0.3	(1.5)	(1.2)
Balance, March 31, 2011	$ 11,377.0	$ --	$ (100.1)	$ 523.1	$ 11,800.0

	Partners' Equity				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2009	$ 1,972.4	$ **	$ (33.3)	$ 8,534.0	$ 10,473.1
Net income	69.9	**	--	322.5	392.4
Operating lease expenses paid by EPCO	--	--	--	0.2	0.2
Cash distributions paid to partners	(73.8)	--	--	--	(73.8)
Cash distributions paid to noncontrolling interest	--	--	--	(351.9)	(351.9)
Cash contributions from noncontrolling interest	--	--	--	417.3	417.3
Acquisition of treasury units	--	--	--	(0.2)	(0.2)
Amortization of equity awards	0.5	--	--	8.0	8.5
Change in value of cash flow hedges	--	--	(1.5)	(42.7)	(44.2)
Proportionate share of other comprehensive income of unconsolidated affiliate	--	--	1.0	--	1.0
Other	--	--	--	(0.3)	(0.3)
Balance, March 31, 2010	$ 1,969.0	$ **	$ (33.8)	$ 8,886.9	$ 10,822.1

See Notes to Unaudited Condensed Consolidated Financial Statements.
** Amount is negligible.

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

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in 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," "Enterprise" 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, and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see Note 1.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which 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 and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P. (NYSE: DEP), which is a consolidated subsidiary of EPO. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and a wholly owned subsidiary of EPO. On April 28, 2011, we, our general partner, and two of our subsidiaries entered into a definitive merger agreement with Duncan Energy Partners and DEP GP. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

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. (NYSE: ETE) and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and Regency Energy Partners LP ("RGNC"). The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). We own noncontrolling interests in Energy Transfer Equity, which we account for using the equity method of accounting.

References to "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. See Note 3 for additional information.

Duncan Energy Partners and Energy Transfer Equity electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"), including annual reports on Form 10-K and quarterly reports on Form 10-Q. The SEC maintains an Internet website at www.sec.gov that contains periodic reports and other information regarding these registrants.

Note 1. Partnership Operations, Organization and Basis of Presentation

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 certain 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 approximately 50,200 miles of onshore and offshore pipelines; 190 million barrels ("MMBbls") of storage capacity for NGLs, refined products and crude oil; and 27 billion cubic feet ("Bcf") of natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation 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 services; 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 six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 11 for additional information regarding our business segments.

We are 100% owned by our limited partners from an economic perspective. We are managed and controlled by Enterprise GP, which has a non-economic general partner interest in us. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC and 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 12 for information regarding the ASA and other related party matters.

Agreement and Plan of Merger with Duncan Energy Partners

On April 28, 2011, we entered into an Agreement and Plan of Merger, dated as of April 28, 2011 (the "Duncan Merger Agreement"), by and among Enterprise, Enterprise GP, EPD MergerCo LLC ("Duncan MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise), Duncan Energy Partners and DEP GP. At the effective time of the merger, Duncan MergerCo will merge with and into Duncan Energy Partners, pursuant to the Duncan Merger Agreement, with Duncan Energy Partners surviving the merger as a wholly owned subsidiary of Enterprise (the "Duncan Merger"), and all of the outstanding Duncan Energy Partners common units at the effective time of the merger will be cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange rate of 1.01 Enterprise common units for each Duncan Energy Partners common unit.

The Duncan Merger Agreement and the Duncan Merger must be approved by the affirmative vote or consent of holders of (i) a majority of the outstanding common units of Duncan Energy Partners and (ii) a majority of the Duncan Energy Partners common units owned by the Duncan Unaffiliated Unitholders (as defined in the Duncan Merger Agreement) that actually vote for or against such approval. In connection with the Duncan Merger Agreement, we, Duncan Energy Partners and Enterprise GTM Holdings L.P., a Delaware limited partnership and a wholly owned subsidiary of Enterprise ("Enterprise GTM"), entered into a Voting Agreement, dated as of April 28, 2011 (the "Voting Agreement"), pursuant to which Enterprise GTM and Enterprise agreed to vote any of the Duncan Energy Partners common units owned by them or their subsidiaries in favor of the adoption of the Duncan Merger Agreement and the Duncan Merger at any meeting of the Duncan Energy Partners unitholders, including the 33,783,587 Duncan Energy Partners common units currently directly owned by Enterprise GTM (representing approximately 58.5% of the outstanding common units of Duncan Energy Partners). The Voting Agreement will terminate upon the termination of the Duncan Merger Agreement.

The Duncan Merger Agreement contains customary representations, warranties and covenants by each of the parties. Completion of the Duncan Merger is conditioned upon, among other things: (i) requisite Duncan Energy Partners unitholder approval of the Duncan Merger Agreement and the Duncan Merger; (ii) applicable regulatory approvals; (iii) the absence of certain legal injunctions or impediments prohibiting the transactions; (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance by Enterprise of the Enterprise common units in connection with the Duncan Merger; (v) the receipt of certain tax opinions; and (vi) approval for the listing of the Enterprise common units issued in connection with the Duncan Merger on the NYSE.

Basis of Presentation

Holdings Merger. On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger. At the effective time of the Holdings Merger, Enterprise GP succeeded as Enterprise's general partner, and each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive Enterprise common units based on an exchange ratio of 1.5 Enterprise common units for each Holdings unit. Enterprise issued an aggregate of 208,813,454 of its common units (net of 23 fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of its common units previously owned by Holdings.

In connection with the Holdings Merger, Enterprise's partnership agreement was amended and restated to effect the cancellation of its general partner's 2% economic general partner interest and incentive distribution rights in Enterprise. In addition, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise on an initial amount of 30,610,000 of Enterprise's 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 applies 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.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger results in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if it were Holdings from an accounting perspective (i.e., the financial statements of Holdings become the historical financial statements of Enterprise). The primary differences between Holdings' and Enterprise's consolidated results of operations were: (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interest. See Note 10 for additional information regarding noncontrolling interests.

The historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 13 for additional information regarding earnings per unit.

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.

Note 2. General Accounting Matters

Our results of operations for the three months ended March 31, 2011 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 and 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 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, 2010 (the "2010 Form 10-K").

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following table presents the activity of our allowance for doubtful accounts for the periods presented:

	For the Three Months Ended March 31,	
	2011	2010
Balance at beginning of period	$ 18.4	$ 16.8
Charged to costs and expenses	0.2	0.7
Deductions (1)	(5.1)	--
Balance at end of period	$ 13.5	$ 17.5

(1) Primarily due to our reassessment of the allowance for doubtful accounts as a result of improved credit ratings of a significant customer, which reduced our exposure to potential uncollectibility.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed. Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 14 for additional information regarding our contingencies.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis.

We apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market values for these items on our balance sheet or income statement. Revenues and costs for these transactions are recognized when volumes are physically delivered or received.

See Note 4 for additional information regarding our derivative instruments and related hedging activities.

Earnings Per Unit

Earnings per unit is based on the amount of income attributable to limited partners and the weighted-average number of units outstanding during the period. See Note 1 for information regarding the retroactive presentation of earnings per unit amounts for the first quarter of 2010 in connection with the Holdings Merger.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. 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

The carrying amounts of cash and cash equivalents (including restricted cash), accounts receivable and accounts payable approximate their fair value. See Note 4 for fair value information associated with our derivative instruments.

The estimated fair value of our fixed-rate debt obligations were approximately $13.93 billion and $12.91 billion at March 31, 2011 and December 31, 2010, respectively. These values 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.

We do not have any long-term investments in debt or equity securities carried at fair value. See Note 7 for summarized financial information of our investments accounted for using the equity method.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas, crude oil and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At March 31, 2011 and December 31, 2010, our restricted cash amounts were $191.6 million and $98.7 million, respectively. See Note 4 for information regarding 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 presented:

	For the Three Months Ended March 31, 2011	2010
Restricted common unit awards	$ 11.4	$ 5.8
Unit option awards	0.9	0.7
Other (1)	(0.5)	2.2
Total compensation expense	$ 11.8	$ 8.7

(1) Primarily consists of unit appreciation rights ("UARs"), phantom units and similar awards. Equity-based compensation expense for the three months ended March 31, 2011 includes a credit of $0.6 million associated with UARs. Also, the amount presented for 2010 consists of awards related to limited partnership interests in the Employee Partnerships.

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

At March 31, 2011, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"), the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan") and the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan"). In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan").

The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through March 31, 2011, a total of 1,318,502 additional common units could be issued.

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, UARs and DERs. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through March 31, 2011, a total of 4,685,352 additional common units could be issued.

The 2010 Plan provides for awards to employees, directors or consultants providing services to Duncan Energy Partners. Awards under the 2010 Plan may be granted in the form of options to purchase Duncan Energy Partners' common units, restricted common units, UARs, phantom units and DERs. Up to 500,000 of Duncan Energy Partners' common units may be issued as awards under the 2010 Plan. After giving effect to awards granted under the plan through March 31, 2011, a total of 489,986 additional common units could be issued. The Duncan Merger Agreement contains restrictions on the issuance of additional awards under the 2010 Plan. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

Restricted Common Unit Awards

Restricted common 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 common unit awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. Restricted common unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted common 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 common unit" represents a time-vested unit. Such awards are non-vested until the required service period expires. Restricted common units are included in the number of common units presented on our Unaudited Condensed Consolidated Balance Sheets.

The fair value of a restricted common 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 common unit awards for the periods presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise restricted common unit awards:		
Restricted common units at December 31, 2010	3,561,614	$ 29.78
Granted (2)	1,350,530	$ 43.70
Vested	(336,227)	$ 32.43
Forfeited	(16,475)	$ 34.37
Restricted common units at March 31, 2011	4,559,442	$ 33.69
Duncan Energy Partners restricted common unit awards:		
Restricted common units at December 31, 2010	--	$ --
Granted (3)	3,666	$ 32.56
Vested (3)	(3,666)	$ 32.56
Restricted common units at March 31, 2011	--	$ --

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2011 was $59.0 million based on a grant date market price of $43.70 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) The aggregate grant date fair value of restricted common unit awards issued in 2011 was $0.1 million based on a grant date market price of $32.56 per unit. These awards vested upon issuance.

Typically, each recipient is also entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid by the respective issuer. Since these restricted common units are participating securities, such distributions are included in cash distributions paid to partners (post-Holdings Merger) and cash distributions paid to noncontrolling interest (pre-Holdings Merger) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows. The following table presents cash distributions paid with respect to our restricted common units and the total intrinsic value of restricted common units that vested during the periods indicated:

	For the Three Months Ended March 31, 2011	2010
Cash distributions paid to restricted common unit holders	$ 2.1	$ 1.5
Total intrinsic value of restricted common unit awards vesting during period	14.7	1.1

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $86.5 million at March 31, 2011, of which our allocated share of the cost is currently estimated to be $84.1 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.2 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, these option awards have a vesting period of four years from the date of grant and 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. In general, our assumptions regarding the expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of risk-free interest rates is based on published yields for U.S. government securities with comparable terms. The unit price volatility and expected distribution yield assumptions are based on several factors, including an analysis of the underlying security's historical market price and its distribution yield over a period of time equal to the expected life of the option, respectively. Compensation expense recorded in connection with unit options is based on the grant date fair value of such awards, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents unit option activity for the periods presented. As of March 31, 2011, only Enterprise 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, 2010	3,753,420	$ 28.08	3.6	$ --
Unit options at March 31, 2011	3,753,420	$ 28.08	3.4	$ --
Options exercisable at March 31, 2011	--		--	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated. There were no vested unit options outstanding at either December 31, 2010 or March 31, 2011.

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding our unit options during the periods presented:

	For the Three Months Ended March 31, 2011	2010
Total intrinsic value of option awards exercised during period	$ --	$ 0.9
Cash received from EPCO in connection with the exercise of unit option awards	--	0.6
Unit option-related reimbursements to EPCO	--	0.9

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $5.8 million at March 31, 2011, of which our allocated share of the cost is currently estimated to be $5.6 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

Other

Unit appreciation rights. UARs entitle the recipient to receive a cash payment on the vesting date of the award equal to the excess, if any, of the then current fair market value of the underlying security over the grant date fair value of the award. UARs are accounted for as liability awards. All of the UARs outstanding at March 31, 2011 are denominated in Enterprise common units.

The following tables present information regarding UARs for the periods presented:

UARs at December 31, 2010	170,104
Vested	(4,102)
Settled or forfeited	(45,000)
UARs at March 31, 2011	121,002

	March 31, 2011	December 31, 2010
Accrued liability for UARs	$ 0.3	$ 1.0

At March 31, 2011, 121,002 UARs that had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf were outstanding. 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. Equity-based compensation expense for the three months ended March 31, 2011 and 2010 includes a credit of $0.6 million and an expense of $0.1 million, respectively, associated with UARs.

Limited partnership interests. EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, limited partnership interests in the Employee Partnerships, which were privately held affiliates of EPCO. These partnerships were liquidated in August 2010. Prior to liquidation, the limited partnership interests 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 Enterprise common units or Holdings' units or a combination of both. Equity-based compensation expense for the three months ended March 31, 2010 includes $1.9 million of expense associated with these limited partnership interests.

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 and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. 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. Derivative instruments typically 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 our 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 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.

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 transactions or a mismatch of terms between the derivative instrument and the hedged item.

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

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 interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at March 31, 2011:

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 2.3%	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
Senior Notes AA	10 fixed-to-floating swaps	$750.0	1/11 to 2/16	3.2% to 1.3%	Fair value hedge
Non-Hedged Swaps	2 floating-to-fixed swaps	$250.0	9/07 to 8/11	0.3% to 4.8%	Mark-to-market
Non-Hedged Swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.3% to 2.0%	Mark-to-market

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for the fixed or floating interest rate stipulated in the derivative instrument. Interest expense for the three months ended March 31, 2011 and 2010 reflects a decrease of $9.7 million and $1.4 million, respectively, attributable to interest rate swaps.

The following table summarizes our forward starting interest rate swaps, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt, outstanding at March 31, 2011:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
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 connection with the issuance of Senior Notes AA and BB (see Note 9), we settled three forward starting swaps in January 2011 having a notional amount of $250 million, resulting in a loss of $5.7 million. This loss will be amortized to earnings (as an increase in interest expense) using the effective interest method over the forecasted hedged period.

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 such price risks, 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 March 31, 2011:

	Volume (1)		
Derivative Purpose	**Current**	**Long-Term** (2)	**Accounting Treatment**
Derivatives designated as hedging instruments:			
Enterprise:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	33.4 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	7.0 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (4)	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	3.0 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	4.1 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	4.3 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	3.6 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	4.0 MMBbls	0.1 MMBbls	Cash flow hedge
Forecasted sales of refined products	4.0 MMBbls	0.1 MMBbls	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	3.6 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	5.2 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise:			
Natural gas risk management activities (5,6)	355.5 Bcf	55.6 Bcf	Mark-to-market
Refined products risk management activities (6)	4.5 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	7.3 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	2.4 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 2013.
(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) Forecasted sales of NGL volumes under Natural gas processing exclude 3.0 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(5) Current and long-term volumes include approximately 151.9 Bcf and 4.1 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 natural 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 December 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.

Certain basis swaps, basis spread options and other financial derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

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 March 31, 2011, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was immaterial and not subject to any credit rating contingent feature. 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			
	March 31, 2011		December 31, 2010		March 31, 2011		December 31, 2010	
	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	$ 46.6	Other current assets	$ 30.3	Other current liabilities	$ 22.0	Other current liabilities	$ 5.5
Interest rate derivatives	Other assets	82.0	Other assets	77.8	Other liabilities	18.9	Other liabilities	26.2
Total interest rate derivatives		128.6		108.1		40.9		31.7
Commodity derivatives	Other current assets	58.7	Other current assets	46.3	Other current liabilities	185.8	Other current liabilities	93.0
Commodity derivatives	Other assets	2.8	Other assets	1.0	Other liabilities	2.7	Other liabilities	1.7
Total commodity derivatives (1)		61.5		47.3		188.5		94.7
Total derivatives designated as hedging instruments		$ 190.1		$ 155.4		$ 229.4		$ 126.4
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 18.1	Other current liabilities	$ 21.0
Interest rate derivatives	Other assets	3.0	Other assets	--	Other liabilities	--	Other liabilities	0.9
Total interest rate derivatives		3.0		--		18.1		21.9
Commodity derivatives	Other current assets	50.9	Other current assets	38.6	Other current liabilities	61.1	Other current liabilities	41.2
Commodity derivatives	Other assets	3.8	Other assets	4.5	Other liabilities	1.5	Other liabilities	5.4
Total commodity derivatives		54.7		43.1		62.6		46.6
Foreign currency derivatives	Other assets	--	Other assets	0.3	Other liabilities	--	Other liabilities	0.1
Total derivatives not designated as hedging instruments		$ 57.7		$ 43.4		$ 80.7		$ 68.6

(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 presented:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative	
		For the Three Months Ended March 31,	
		2011	2010
Interest rate derivatives	Interest expense	$ (12.3)	$ 7.4
Commodity derivatives	Revenue	0.3	(1.8)
Total		$ (12.0)	$ 5.6

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item	
		For the Three Months Ended March 31,	
		2011	2010
Interest rate derivatives	Interest expense	$ 11.3	$ (7.4)
Commodity derivatives	Revenue	(1.3)	1.9
Total		$ 10.0	$ (5.5)

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 presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income/(Loss) on Derivative – Effective Portion	
	For the Three Months Ended March 31,	
	2011	2010
Interest rate derivatives	$ 14.1	$ (7.5)
Commodity derivatives – Revenue (1)	(155.4)	(7.1)
Commodity derivatives – Operating costs and expenses	4.0	(51.8)
Foreign currency derivatives	--	(0.1)
Total	$ (137.3)	$ (66.5)

(1) The increase in other comprehensive loss for the first quarter of 2011 is primarily due to the impact of rising crude oil, refined products and NGL prices on our derivative instruments designated as cash flow hedges of future physical sales transactions.

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 March 31,	
		2011	2010
Interest rate derivatives	Interest expense	$ (1.5)	$ (6.1)
Commodity derivatives	Revenue	(69.2)	(15.8)
Commodity derivatives	Operating costs and expenses	0.3	(0.7)
Foreign currency derivatives	Other income	--	0.3
Total		$ (70.4)	$ (22.3)

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative	
		For the Three Months Ended March 31,	
		2011	2010
Commodity derivatives	Revenue	$ (0.1)	$ --
Commodity derivatives	Operating costs and expenses	--	(0.6)
Total		$ (0.1)	$ (0.6)

Over the next twelve months, we expect to reclassify $6.5 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 $114.3 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, $26.4 million as an increase in operating costs and expenses and $87.9 million as a decrease in revenue.

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 presented:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative For the Three Months Ended March 31, 2011	2010
Interest rate derivatives	Interest expense	$ (2.1)	$ --
Commodity derivatives	Revenue	3.8	3.9
Commodity derivatives	Operating costs and expenses	--	(1.5)
Total		$ 1.7	$ 2.4

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 following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at the date indicated. These assets and liabilities are measured on a recurring basis and are classified within the table based on the lowest level of input that is significant to their respective fair value. Our assessment of the relative significance of such inputs requires judgment.

	At March 31, 2011			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 131.6	$ --	$ 131.6
Commodity derivatives	47.1	63.6	5.5	116.2
Total	$ 47.1	$ 195.2	$ 5.5	$ 247.8
Financial liabilities:				
Interest rate derivatives	$ --	$ 59.0	$ --	$ 59.0
Commodity derivatives	137.2	108.8	5.1	251.1
Total	$ 137.2	$ 167.8	$ 5.1	$ 310.1

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 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 (i) are 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 financial models that incorporate the implied forward London Interbank Offered Rate 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 management's 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 consist of ethane, normal butane and natural gasoline-based contracts with terms greater than one year and certain options used to hedge natural gas storage inventory and transportation capacities. In addition, we often rely on price quotes from reputable brokers who publish price quotes on certain products and compare these prices to other reputable brokers for the same products in the same markets whenever possible. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

Transfers within the fair value hierarchy routinely occur for certain term contracts as prices and other inputs used for the valuation of future delivery periods become more observable with the passage of time. Other transfers are made periodically in response to changing market conditions that affect liquidity, price observability and other inputs used in determining valuations. Based on an assessment completed during the first quarter of 2011, we transferred ethane, normal butane and natural gasoline-based contracts with terms ranging from two months to one year from Level 3 to Level 2. These transfers were made after a sustained increase in the observability of forward prices for these energy commodity products relative to the date range stated above as demonstrated by narrowing bid/offer spreads, higher transaction volumes and more activity and liquidity for these types of contracts. With the exception of the transfers noted above, no other transfers were made between fair value levels during the quarter.

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 presented:

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
Balance, January 1	$ (25.9)	$ 5.7
Total gains (losses) included in:		
Net income (1)	(0.5)	(3.6)
Other comprehensive income (loss)	16.2	(8.3)
Settlements	0.8	3.6
Transfers out of Level 3 (2)	9.8	--
Balance, March 31	$ 0.4	$ (2.6)

(1) There were unrealized losses of $0.2 million and unrealized gains of $0.5 million included in these amounts for the three months ended March 31, 2011 and 2010, respectively.
(2) Transfers out of Level 3 into Level 2 were primarily due to the change in observability of forward NGL prices as described above.

Nonfinancial Assets and Liabilities

During the three months ended March 31, 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. The non-cash asset impairment charges we recorded during the three months ended March 31, 2010 are a component of operating costs and expenses.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	March 31, 2011	December 31, 2010
Working inventory (1)	$ 525.4	$ 690.9
Forward sales inventory (2)	275.4	443.1
Total inventory	$ 800.8	$ 1,134.0

(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.
(2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties), these volumes are valued at market-based prices during the month in which they are acquired. In general, our inventory levels have decreased since December 31, 2010 due to a reduction in propane and butane inventories attributable to seasonal supply and demand fluctuations and a reduction in inventories attributable to the settlement of forward sales contracts.

The following table summarizes our cost of sales and lower of cost or market ("LCM") adjustment amounts for the periods presented:

	For the Three Months Ended March 31,	
	2011	2010
Cost of sales (1)	$ 8,819.3	$ 7,342.3
LCM adjustments	1.2	5.7

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations. Quarter-to-quarter 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	March 31, 2011	December 31, 2010
Plants, pipelines and facilities (1)	3-45 (6)	$ 19,552.3	$ 19,388.4
Underground and other storage facilities (2)	5-40 (7)	1,491.3	1,477.8
Platforms and facilities (3)	20-31	637.5	637.5
Transportation equipment (4)	3-10	120.0	119.1
Marine vessels (5)	15-30	563.7	560.0
Land		123.4	123.4
Construction in progress		2,168.8	1,607.2
Total		24,657.0	23,913.4
Less accumulated depreciation		4,764.1	4,580.5
Property, plant and equipment, net		$ 19,892.9	$ 19,332.9

(1) Plants and pipelines include processing plants; NGL, natural gas, crude oil and petrochemical and refined products 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 tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major assets within this category are: 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 assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

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

	For the Three Months Ended March 31,	
	2011	2010
Depreciation expense (1)	$ 186.5	$ 180.3
Capitalized interest (2)	17.2	10.5

(1) Depreciation expense is a component of "Costs and expenses" as presented in 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.

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 contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and leases of plant sites. In addition, we have recorded AROs based on government regulations triggered by the abandonment or retirement of (i) certain underground storage facilities and related above-ground brine storage pits, (ii) offshore Gulf of Mexico assets and (iii) certain marine vessels. Our AROs may also result from regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2010:

ARO liability balance, December 31, 2010	$ 97.1
Revisions in estimated cash flows	1.0
Accretion expense	1.6
Liabilities settled during period	(0.2)
ARO liability balance, March 31, 2011	$ 99.5

Property, plant and equipment at March 31, 2011 and December 31, 2010 includes $34.2 million and $34.1 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents forecast accretion expense associated with our AROs for the years presented:

Remainder of 2011	**2012**	**2013**	**2014**	**2015**
$ 4.8	$ 5.0	$ 5.4	$ 5.8	$ 5.5

Certain of our unconsolidated affiliates have AROs recorded at March 31, 2011 and December 31, 2010 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 7. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. We group our investments in unconsolidated affiliates according to the business segment to which they relate (see Note 11 for a general discussion of our business segments). The following table shows our investments in unconsolidated affiliates by business segment at the dates indicated:

	Ownership Interest at March 31, 2011	March 31, 2011	December 31, 2010
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 33.5	$ 31.9
K/D/S Promix, L.L.C. ("Promix")	50%	42.4	43.5
Baton Rouge Fractionators LLC	32.2%	21.7	21.9
Skelly-Belvieu Pipeline Company, L.L.C.	50%	34.0	34.2
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	6.7	6.4
White River Hub, LLC ("White River Hub")	50%	26.1	26.2
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company ("Seaway")	50%	171.7	172.2
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	55.1	57.2
Cameron Highway Oil Pipeline Company	50%	231.8	233.7
Deepwater Gateway, L.L.C.	50%	97.7	98.4
Neptune Pipeline Company, L.L.C.	25.7%	53.0	53.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	10.0	10.1
Centennial Pipeline LLC ("Centennial")	50%	61.5	63.1
Other (2)	Various	3.6	3.6
Other Investments:			
Energy Transfer Equity	17.5%	1,421.1	1,436.8
Total		$ 2,269.9	$ 2,293.1

(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.

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

	For the Three Months Ended March 31, 2011	2010
NGL Pipelines & Services	$ 5.9	$ 3.3
Onshore Natural Gas Pipelines & Services	1.2	1.3
Onshore Crude Oil Pipelines & Services	(0.5)	2.3
Offshore Pipelines & Services	8.3	11.8
Petrochemical & Refined Products Services	(5.0)	(2.7)
Other Investments	6.3	10.6
Total	$ 16.2	$ 26.6

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:

	March 31, 2011	December 31, 2010
NGL Pipelines & Services	$ 25.4	$ 25.7
Onshore Crude Oil Pipelines & Services	19.7	19.7
Offshore Pipelines & Services	15.7	16.0
Petrochemical & Refined Products Services	3.0	3.0
Other Investments (1)	1,516.0	1,525.1
Total	$ 1,579.8	$ 1,589.5

(1) Holdings' investment in Energy Transfer Equity exceeded its share of the historical cost of the underlying net assets of such investee by $1.66 billion in May 2007. At March 31, 2011, this basis differential decreased to $1.52 billion and consisted of the following: $481.3 million attributed to fixed assets; $509.7 million attributed to the IDRs (an indefinite-life intangible asset) held by Energy Transfer Equity in the cash flows of ETP; $191.7 million attributed to amortizable intangible assets and $333.3 million attributed to equity method goodwill. These unamortized excess cost amounts are being amortized over their estimated economic lives of 20-27 years.

We amortize such excess cost amounts as a reduction in equity earnings in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods presented:

	For the Three Months Ended March 31,	
	2011	2010
NGL Pipelines & Services	$ 0.3	$ 0.2
Onshore Crude Oil Pipelines & Services	0.2	0.2
Offshore Pipelines & Services	0.3	0.3
Petrochemical & Refined Products Services	--	0.7
Other Investments	9.1	9.2
Total	$ 9.9	$ 10.6

Summarized Income Statement Information of Unconsolidated Affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	March 31, 2011			March 31, 2010		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services	$ 100.1	$ 23.4	$ 23.4	$ 74.8	$ 13.1	$ 13.0
Onshore Natural Gas Pipelines & Services	35.5	2.6	2.6	42.3	2.5	2.4
Onshore Crude Oil Pipelines & Services	11.2	0.5	0.5	18.5	7.3	7.3
Offshore Pipelines & Services	46.3	18.9	18.7	55.0	29.2	28.7
Petrochemical & Refined Products Services	10.1	(7.0)	(9.2)	8.6	0.6	(0.3)
Other Investments (1)	1,989.1	364.2	88.6	1,872.0	338.9	112.8

(1) Net income for Energy Transfer Equity represents net income attributable to the partners of Energy Transfer Equity.

With the exception of Energy Transfer Equity, all of these investments are in untraded privately held companies, the fair values of which are not practicable to estimate. At March 31, 2011, the fair value of our investment in Energy Transfer Equity was $1.75 billion based on the closing market price of Energy Transfer Equity's common units on that date.

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	March 31, 2011			December 31, 2010		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (112.4)	$ 228.4	$ 340.8	$ (106.7)	$ 234.1
Contract-based intangibles	287.5	(156.6)	130.9	322.2	(176.6)	145.6
Segment total	628.3	(269.0)	359.3	663.0	(283.3)	379.7
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(173.2)	990.4	1,163.6	(160.8)	1,002.8
Contract-based intangibles	565.3	(329.5)	235.8	565.3	(322.0)	243.3
Segment total	1,728.9	(502.7)	1,226.2	1,728.9	(482.8)	1,246.1
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	9.7	(3.8)	5.9	9.7	(3.7)	6.0
Contract-based intangibles	0.4	(0.2)	0.2	0.4	(0.2)	0.2
Segment total	10.1	(4.0)	6.1	10.1	(3.9)	6.2
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(121.0)	84.8	205.8	(118.1)	87.7
Contract-based intangibles	1.2	(0.3)	0.9	1.2	(0.2)	1.0
Segment total	207.0	(121.3)	85.7	207.0	(118.3)	88.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.7	(25.2)	79.5	104.7	(23.8)	80.9
Contract-based intangibles	60.3	(23.1)	37.2	60.3	(20.2)	40.1
Segment total	165.0	(48.3)	116.7	165.0	(44.0)	121.0
Total all segments	$ 2,739.3	$ (945.3)	$ 1,794.0	$ 2,774.0	$ (932.3)	$ 1,841.7

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

	For the Three Months Ended March 31,	
	2011	2010
NGL Pipelines & Services	$ 10.4	$ 9.3
Onshore Natural Gas Pipelines & Services	19.9	14.2
Onshore Crude Oil Pipelines & Services	0.1	0.1
Offshore Pipelines & Services	3.0	3.4
Petrochemical & Refined Products Services	4.3	2.6
Total	$ 37.7	$ 29.6

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

Remainder of 2011	2012	2013	2014	2015
$ 105.9	$ 132.4	$ 127.1	$ 127.2	$ 125.8

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

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At March 31, 2011, the carrying value of our customer relationship intangible assets was $1.39 billion.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At March 31, 2011, the carrying value of our contract-based intangible assets was $405.0 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 beginning of each fiscal year.

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%).

There have been no changes to our goodwill amounts since those reported in our 2010 Form 10-K.

Note 9. Debt Obligations

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

	March 31, 2011	December 31, 2010
EPO senior debt obligations:		
$1.75 Billion Multi-Year Revolving Credit Facility, variable-rate, due November 2012	$ --	$ 648.0
Petal GO Zone Bonds, variable-rate, due August 2034	57.5	57.5
Senior Notes B, 7.50% fixed-rate, due February 2011	--	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 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	400.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	--
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes	40.1	40.1
Duncan Energy Partners' debt obligations:		
DEP Term Loan, variable-rate, due December 2011	282.3	282.3
DEP $850 Million Multi-Year Revolving Credit Facility ,variable-rate, due October 2013	215.5	106.0
DEP $400 Million Term Loan Facility, variable-rate, due October 2013	400.0	400.0
Total principal amount of senior debt obligations	12,505.3	11,993.8
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	14,038.0	13,526.5
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments (1)	38.1	49.3
Unamortized discounts, net of premiums	(29.5)	(24.0)
Unamortized deferred net gains related to terminated interest rate swaps (1)	9.3	11.7
Total other, non-principal amounts	17.9	37.0
Less current maturities of debt (2)	(782.3)	(282.3)
Total long-term debt	$ 13,273.6	$ 13,281.2

(1) See Note 4 for information regarding our interest rate hedging activities.
(2) We expect to refinance the current maturities of our debt obligations prior to their maturity.

Letters of Credit

At March 31, 2011, 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 L.P. acts as guarantor of the consolidated 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.

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 or amounts of our consolidated debt obligations since those reported in our 2010 Form 10-K.

At March 31, 2011, EPO's Multi-Year Revolving Credit Facility had no borrowings outstanding. Available borrowing capacity under this revolving credit facility is $1.75 billion.

Issuance of Senior Notes AA and BB. In January 2011, EPO issued $750.0 million in principal amount of 5-year unsecured Senior Notes AA and $750.0 million in principal amount of 30-year unsecured Senior Notes BB. Senior Notes AA were issued at 99.901% of their principal amount, have a fixed interest rate of 3.20%, and mature on February 1, 2016. Senior Notes BB were issued at 99.317% of their principal amount, have a fixed interest rate of 5.95%, and mature on February 1, 2041. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay $450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes.

Senior Notes AA and BB rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes AA and BB are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Cancellation of Canadian Revolving Credit Facility. As of December 31, 2010, there were no debt obligations outstanding under this $30 million revolving credit facility. This facility was cancelled in January 2011.

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at March 31, 2011.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligations during the three months ended March 31, 2011:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO Multi-Year Revolving Credit Facility	0.75% to 3.25%	0.82%
DEP Term Loan	1.06% to 1.16%	1.09%
DEP Multi-Year Revolving Credit Facility	2.01% to 2.16%	2.06%
DEP $400 Million Term Loan Facility	2.26% to 2.51%	2.34%
Petal GO Zone Bonds	0.23% to 0.33%	0.25%

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	Remainder of 2011	2012	2013	2014	2015	After 2015
Revolving Credit Facilities	$ 215.5	$ --	$ --	$ 215.5	$ --	$ --	$ --
Senior Notes	11,550.0	--	1,000.0	1,200.0	1,150.0	650.0	7,550.0
Term Loans	682.3	282.3	--	400.0	--	--	--
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Other	57.5	--	--	--	--	--	57.5
Total	$ 14,038.0	$ 282.3	$ 1,000.0	$ 1,815.5	$ 1,150.0	$ 650.0	$ 9,140.2

Debt Obligations of Unconsolidated Affiliates

At March 31, 2011, we had two privately held unconsolidated affiliates – Poseidon and Centennial – with long-term debt obligations. The following table shows (i) our ownership interest in each entity at March 31, 2011, (ii) the total debt of each entity at March 31, 2011 (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 2011	2012	2013	2014	2015	After 2015
Poseidon	36%	$ 92.0	$ 92.0	$ --	$ --	$ --	$ --	$ --
Centennial	50%	108.7	6.8	8.9	8.6	8.6	8.6	67.2
Total		$ 200.7	$ 98.8	$ 8.9	$ 8.6	$ 8.6	$ 8.6	$ 67.2

The credit agreements of Poseidon and Centennial include customary financial and other covenants. These businesses were in compliance with such financial covenants at March 31, 2011. 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.

On March 31, 2011, Evangeline made the final scheduled payment of $3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

We refinanced the Poseidon revolving credit facility in April 2011. The new replacement facility matures in April 2015 and has a borrowing capacity of $125 million.

At March 31, 2011 and December 31, 2010, Energy Transfer Equity had approximately $9.6 billion and $9.4 billion, respectively, of consolidated debt obligations outstanding. Since we own only limited partner interests in Energy Transfer Equity, we are not liable for its standalone or consolidated indebtedness.

Note 10. Equity and Distributions

Partners' Equity

Pre-Holdings Merger. As discussed in Note 1, the historical comparative financial statements presented herein are the financial statements of Holdings for periods prior to the effective date of the Holdings Merger. The following table summarizes changes in the number of Holdings' limited partner Units outstanding during the first quarter of 2010.

Balance, January 1, 2010	139,191,640
Issuance of Units to directors of the general partner of Holdings	2,991
Balance, March 31, 2010	139,194,631

Post-Holdings Merger. On November 22, 2010, the 139,195,064 Holdings Units outstanding at the effective date of the merger converted at a ratio of 1.5 to one and, as a result, Holdings' unitholders received 208,813,454 Enterprise common units (net of 23 fractional Enterprise common units that were cashed out).

In addition, the historical noncontrolling interest of Holdings related to limited partner interests in Enterprise that were owned by third parties and related parties other than Holdings was reclassified to limited partners' equity at the effective date of the Holdings Merger. See "Noncontrolling Interest" below for information regarding our noncontrolling interest holders.

Following the Holdings Merger, our partners' equity reflects the various classes of limited partner interests of Enterprise (e.g., common units (including unvested restricted common units) and Class B units). The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2010:

	Common Units	Class B Units	Treasury Units
Balance, December 31, 2010	843,681,572	4,520,431	--
Common units issued in connection with DRIP and EUPP	506,908	--	--
Restricted common units issued	1,350,530	--	--
Forfeiture of restricted common units	(16,475)	--	--
Acquisition of treasury units	(91,126)	--	91,126
Cancellation of treasury units	--	--	(91,126)
Balance, March 31, 2011	845,431,409	4,520,431	--

Restricted common units are a component of common units as presented on our Unaudited Condensed Consolidated Balance Sheets.

The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the TEPPCO Merger in October 2009. 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.

During the three months ended March 31, 2011, 336,227 restricted common unit awards vested and were converted to common units. Of this amount, 91,126 were sold back to us by employees to cover related withholding tax requirements. We cancelled such treasury units immediately upon acquisition.

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. In January 2011, EPO utilized the 2010 Shelf to issue its Senior Notes AA and BB (see Note 9).

Enterprise also has registration statements on file with the SEC in connection with its distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP"). After taking into account limited partner units issued under these registration statements through March 31, 2011, Enterprise may issue an additional 27,940,166 common units under its DRIP and 53,940 common units under its EUPP. The following table reflects the number of common units issued and the net cash proceeds received from Enterprise's DRIP and EUPP during the three months ended March 31, 2011:

	Number of Common Units Issued	Net Cash Proceeds
February DRIP and EUPP	506,908	$ 21.0

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

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 related net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

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

	March 31, 2011	December 31, 2010
Commodity derivative instruments (1)	$ (114.3)	$ (31.8)
Interest rate derivative instruments (1)	13.5	(2.1)
Foreign currency translation adjustment (2)	1.7	1.7
Pension and postretirement benefit plans	(0.1)	(0.4)
Proportionate share of other comprehensive loss of unconsolidated affiliates, primarily Energy Transfer Equity	(2.0)	(1.0)
Subtotal	(101.2)	(33.6)
Amounts attributable to noncontrolling interests	1.1	1.1
Total accumulated other comprehensive loss in partners' equity	$ (100.1)	$ (32.5)

(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 Interest

For periods prior to the Holdings Merger, that portion of the income of Enterprise attributable to its limited partner interests owned by third parties and related parties other than Holdings are included in net income attributable to noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Operations. Additionally, cash distributions paid to and cash contributions received from the limited partners of Enterprise other than Holdings are reflected as a component of cash distributions paid to and cash contributions received from noncontrolling interests, as appropriate.

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

	March 31, 2011	December 31, 2010
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (1)	$ 408.1	$ 410.4
Related party owners of Duncan Energy Partners (2)	1.7	1.7
Joint venture partners (3)	114.4	115.6
Accumulated other comprehensive loss attributable to noncontrolling interest	(1.1)	(1.1)
Total noncontrolling interest	$ 523.1	$ 526.6

(1) Consists of non-affiliate public unitholders of Duncan Energy Partners.
(2) Consists of unitholders of Duncan Energy Partners that are related party affiliates.
(3) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole, 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 attributable to noncontrolling interest as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods presented:

	For the Three Months Ended March 31,	
	2011	2010
Limited partners of Enterprise	$ --	$ 306.5
Limited partners of Duncan Energy Partners	7.9	8.7
Joint venture partners	5.9	7.3
Total	$ 13.8	$ 322.5

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 Statements of Consolidated Equity for the periods presented:

	For the Three Months Ended March 31,	
	2011	2010
Cash distributions paid to noncontrolling interest:		
Limited partners of Enterprise	$ --	$ 334.5
Limited partners of Duncan Energy Partners	10.9	10.6
Joint venture partners	6.3	6.8
Total cash distributions paid to noncontrolling interest	$ 17.2	$ 351.9
Cash contributions from noncontrolling interest:		
Limited partners of Enterprise	$ --	$ 417.1
Limited partners of Duncan Energy Partners	0.6	0.2
Joint venture partners	0.7	--
Total cash contributions from noncontrolling interest	$ 1.3	$ 417.3

Cash distributions paid to the limited partners of Enterprise (prior to the Holdings Merger) and Duncan Energy Partners represent the quarterly cash distributions paid by these entities to their unitholders, excluding amounts paid to Holdings that were eliminated in the preparation of our consolidated financial statements. Similarly, cash contributions received from the limited partners of Enterprise (prior to the Holdings Merger) and Duncan Energy Partners represent net cash proceeds each entity received from the issuance of limited partner units, excluding contributions made by Holdings that were eliminated in consolidation.

Cash Distributions

On April 14, 2011, the Board of Directors of our general partner declared a cash distribution of $0.5975 per common unit. This distribution was paid on May 6, 2011 to unitholders of record as of the close of business on Friday, April 29, 2011.

In November 2010, in connection with the Holdings Merger (see Note 1), a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise on an initial amount of 30,610,000 of its Enterprise common units for a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver applies 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 quarterly cash distributions paid on February 7, 2011 and May 6, 2011 excluded the Designated Units.

Note 11. Business Segments

We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion 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 interest.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Duncan Energy Partners.

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

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
Revenues	$ 10,183.7	$ 8,544.5
Less: Operating costs and expenses	(9,537.1)	(7,971.9)
Add: Equity in income of unconsolidated affiliates	16.2	26.6
Depreciation, amortization and accretion in operating costs and expenses (1)	230.8	212.4
Non-cash asset impairment charges	--	1.5
Operating lease expenses paid by EPCO	0.2	0.2
Gains from asset sales and related transactions in operating costs and expenses (2)	(18.4)	(7.3)
Total segment gross operating margin	$ 875.4	$ 806.0

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

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented:

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
Total segment gross operating margin	$ 875.4	$ 806.0
Adjustments to reconcile total segment gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(230.8)	(212.4)
Non-cash asset impairment charges	--	(1.5)
Operating lease expenses paid by EPCO	(0.2)	(0.2)
Gains from asset sales and related transactions in operating costs and expenses	18.4	7.3
General and administrative costs	(37.9)	(40.3)
Operating income	624.9	558.9
Other expense, net	(183.3)	(157.8)
Income before provision for income taxes	$ 441.6	$ 401.1

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

	Reportable Business Segments							
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:								
Three months ended March 31, 2011	$ 4,055.4	$ 871.7	$ 3,370.6	$ 60.6	$ 1,575.3	$ --	$ --	$ 9,933.6
Three months ended March 31, 2010	3,666.3	1,111.1	2,386.7	86.5	1,061.5	--	--	8,312.1
Revenues from related parties:								
Three months ended March 31, 2011	201.4	44.9	--	3.8	--	--	--	250.1
Three months ended March 31, 2010	180.0	50.4	(0.1)	2.1	--	--	--	232.4
Intersegment and intrasegment revenues:								
Three months ended March 31, 2011	3,474.6	270.9	707.1	1.7	473.1	--	(4,927.4)	--
Three months ended March 31, 2010	2,547.2	215.6	24.7	0.4	257.8	--	(3,045.7)	--
Total revenues:								
Three months ended March 31, 2011	7,731.4	1,187.5	4,077.7	66.1	2,048.4	--	(4,927.4)	10,183.7
Three months ended March 31, 2010	6,393.5	1,377.1	2,411.3	89.0	1,319.3	--	(3,045.7)	8,544.5
Equity in income (loss) of unconsolidated affiliates:								
Three months ended March 31, 2011	5.9	1.2	(0.5)	8.3	(5.0)	6.3	--	16.2
Three months ended March 31, 2010	3.3	1.3	2.3	11.8	(2.7)	10.6	--	26.6
Gross operating margin:								
Three months ended March 31, 2011	504.4	159.2	31.8	61.3	112.4	6.3	--	875.4
Three months ended March 31, 2010	437.3	130.3	26.7	81.1	120.0	10.6	--	806.0
Segment assets:								
At March 31, 2011	7,640.3	8,196.8	913.7	1,977.9	3,745.9	1,421.1	2,168.8	26,064.5
At December 31, 2010	7,665.5	8,184.8	917.5	2,004.9	3,758.7	1,436.8	1,607.2	25,575.4
Property, plant and equipment, net: (see Note 6)								
At March 31, 2011	6,808.2	6,626.7	424.7	1,372.5	2,492.0	--	2,168.8	19,892.9
At December 31, 2010	6,813.1	6,595.0	427.9	1,390.9	2,498.8	--	1,607.2	19,332.9
Investments in unconsolidated affiliates: (see Note 7)								
At March 31, 2011	131.6	32.8	171.7	437.6	75.1	1,421.1	--	2,269.9
At December 31, 2010	131.5	32.6	172.2	443.2	76.8	1,436.8	--	2,293.1
Intangible assets, net: (see Note 8)								
At March 31, 2011	359.3	1,226.2	6.1	85.7	116.7	--	--	1,794.0
At December 31, 2010	379.7	1,246.1	6.2	88.7	121.0	--	--	1,841.7
Goodwill: (see Note 8)								
At March 31, 2011	341.2	311.1	311.2	82.1	1,062.1	--	--	2,107.7
At December 31, 2010	341.2	311.1	311.2	82.1	1,062.1	--	--	2,107.7

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

	For the Three Months Ended March 31,	
	2011	2010
NGL Pipelines & Services:		
Sales of NGLs	$ 4,057.1	$ 3,664.1
Sales of other petroleum and related products	0.6	0.5
Midstream services	199.1	181.7
Total	4,256.8	3,846.3
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	712.7	975.2
Midstream services	203.9	186.3
Total	916.6	1,161.5
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	3,348.2	2,367.3
Midstream services	22.4	19.3
Total	3,370.6	2,386.6
Offshore Pipelines & Services:		
Sales of natural gas	0.3	0.4
Sales of crude oil	3.3	2.1
Midstream services	60.8	86.1
Total	64.4	88.6
Petrochemical & Refined Products Services:		
Sales of other petroleum and related products	1,382.8	932.6
Midstream services	192.5	128.9
Total	1,575.3	1,061.5
Total consolidated revenues	$ 10,183.7	$ 8,544.5
Consolidated costs and expenses		
Operating costs and expenses:		
Cost of sales related to our marketing activities	$ 7,930.1	$ 6,649.2
Depreciation, amortization and accretion	230.8	212.4
Gains from asset sales and related transactions	(18.4)	(7.3)
Non-cash asset impairment charges	--	1.5
Other operating costs and expenses	1,394.6	1,116.1
General and administrative costs	37.9	40.3
Total consolidated costs and expenses	$ 9,575.0	$ 8,012.2

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of NGLs, natural gas, crude oil and other petroleum and related products; however, these higher commodity prices also increase the associated cost of sales as purchase costs rise.

Note 12. Related Party Transactions

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

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
Revenues – related parties:		
Energy Transfer Equity and subsidiaries	$ 210.2	$ 186.6
Other unconsolidated affiliates	39.9	45.8
Total revenue – related parties	$ 250.1	$ 232.4
Costs and expenses – related parties:		
EPCO and affiliates	$ 173.0	$ 158.9
Energy Transfer Equity and subsidiaries	267.4	176.9
Other unconsolidated affiliates	10.2	12.2
Total costs and expenses – related parties	$ 450.6	$ 348.0

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

	March 31, 2011	December 31, 2010
Accounts receivable - related parties:		
EPCO and affiliates	$ 0.1	$ --
Energy Transfer Equity and subsidiaries	15.1	21.4
Other unconsolidated affiliates	15.8	15.4
Total accounts receivable – related parties	$ 31.0	$ 36.8
Accounts payable - related parties:		
EPCO and affiliates	$ 62.3	$ 88.0
Energy Transfer Equity and subsidiaries	67.2	36.7
Other unconsolidated affiliates	9.5	8.4
Total accounts payable – related parties	$ 139.0	$ 133.1

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; and

§ Enterprise GP, our sole general partner.

EPCO is a privately held company controlled collectively by the EPCO Trustees. At March 31, 2011, 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 the following limited partner interests in us:

Number of Units	Percentage of Outstanding Units
338,282,914 (1)	39.8%

(1) Includes 4,520,431 Class B units.

Dan Duncan LLC owns 100% of our general partner, Enterprise GP.

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO and its privately held subsidiaries depend on the cash distributions they receive from us (including Holdings prior to the Holdings Merger) 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 presented:

	For the Three Months Ended March 31,	
	2011	2010
Enterprise	$ 172.1	$ 82.9
Holdings	--	57.3
Total distributions	$ 172.1	$ 140.2

Substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by 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 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 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.

§ 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 15 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 its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its 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 entity's business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods presented:

	For the Three Months Ended March 31,	
	2011	2010
Operating costs and expenses	$ 147.4	$ 134.4
General and administrative expenses	25.6	24.5
Total costs and expenses	$ 173.0	$ 158.9

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 and Enterprise GP, Duncan Energy Partners and 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, Duncan Energy Partners and our respective general partners.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

§ We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $30.7 million and $37.8 million for the three months ended March 31, 2011 and 2010, 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 $3.2 million and $3.1 million for the three months ended March 31, 2011 and 2010, respectively. Expenses with Promix were $9.0 million and $8.6 million for the three months ended March 31, 2011 and 2010, respectively.

§ We paid $0.2 million and $2.6 million to Centennial for the three months ended March 31, 2011 and 2010 for other pipeline transportation services, respectively.

§ For the three months ended March 31, 2011 and 2010, we paid Seaway $0.7 million and $1.1 million, respectively, for transportation and tank rentals in connection with our crude oil marketing activities.

§ For the three months ended March 31, 2011 and 2010, we paid White River Hub $1.7 million and $1.4 million, respectively, primarily for firm capacity reservation fees.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $3.2 million and $2.9 million for the three months ended March 31, 2011 and 2010, respectively.

§ We have a long-term sales contract with a subsidiary of Energy Transfer Equity. In addition, we and another subsidiary of ETP transport natural gas on each other's systems and share operating expenses on certain pipelines. A subsidiary of ETP also sells natural gas to us. See previous table for related party revenue and expense amounts recorded by us in connection with Energy Transfer Equity.

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 that are under common control. Duncan Energy Partners is engaged in the business of: (i) NGL transportation, fractionation and marketing; (ii) storage of NGL, petrochemical and refined products; (iii) transportation of petrochemical and refined 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 March 31, 2011, 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 March 31, 2011, EPO beneficially owned 58.5% of Duncan Energy Partners' common units 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. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

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 budgeted cost of the Haynesville Extension project is approximately $1.5 billion (including capitalized interest), with Duncan Energy Partners' share currently estimated at $990 million. In order to fund its capital spending 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.

Note 13. Earnings Per Unit

The earnings per unit amounts included in these financial statements have been retroactively presented in connection with the unit-for-unit exchange that occurred under the Holdings Merger.

Basic and diluted earnings per unit amounts for periods prior to the Holdings Merger are based on net income attributable to partners, divided by the applicable weighted-average number of Holdings' units outstanding for the period adjusted for the merger exchange ratio of 1.5 Enterprise common units for each Holdings unit. For these periods, net income attributable to partners represents net income allocated to the former owners of Holdings, which was determined after amounts allocated to noncontrolling interests (which included net income allocated to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings).

Following the Holdings Merger, basic earnings per unit is computed by dividing net income attributable to our limited partner interests by the weighted-average number of our distribution-bearing units outstanding during a period (excluding the Designated Units).

Diluted earnings per unit is computed by dividing net income or loss available to our limited partner interests by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of our Class B units outstanding during a period, (iii) the weighted-average number of Designated Units outstanding during a period and (iv) 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, Designated 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 following table presents our calculation of basic and diluted earnings per unit for the periods presented:

	For Three Months Ended March 31,	
	2011	2010
BASIC EARNINGS PER UNIT		
Numerator:		
Net income attributable to partners	$ 420.7	$ 69.9
General partner interest in net income	--	*
Net income available to limited partners	$ 420.7	$ 69.9
Denominator:		
Common units	809.9	208.8
Time-vested restricted common units	4.0	--
Total	813.9	208.8
Basic earnings per unit:		
Net income attributable to partners	$ 0.52	$ 0.33
General partner interest in net income	--	*
Net income available to limited partners	$ 0.52	$ 0.33
DILUTED EARNINGS PER UNIT		
Numerator:		
Net income attributable to partners	$ 420.7	$ 69.9
General partner interest in net income	--	*
Net income available to limited partners	$ 420.7	$ 69.9
Denominator:		
Common units	809.9	208.8
Time-vested restricted common units	4.0	--
Class B units	4.5	--
Designated Units	30.6	--
Incremental option units	1.3	--
Total	850.3	208.8
Diluted earnings per unit:		
Net income attributable to partners	$ 0.49	$ 0.33
General partner interest in net income	--	*
Net income available to limited partners	$ 0.49	$ 0.33

* Amount is negligible.

Note 14. Commitments and Contingencies

Litigation

As part of our normal business activities, we may be named 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 15 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 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 Holdings Merger (see Note 1) and that Holdings aided and abetted in these alleged breaches of fiduciary duties. On October 18, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. On March 18, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal of all claims pending in that action without prejudice, with each party to bear its own costs and fees. The Court granted the Stipulation and Proposed Order of Dismissal on March 18, 2011.

On September 29, 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 failing to make adequate disclosures, in connection with the 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. On October 18, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. On March 18, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal of all claims pending in that action without prejudice, with each party to bear its own costs and fees. The Court granted the Stipulation and Proposed Order of Dismissal on March 18, 2011.

Additionally, on September 23, 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 with the Holdings Merger and that Holdings and the other defendants aided and abetted in the alleged breach. On October 18, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. We cannot predict the outcome of this or any other lawsuit nor the amount of time and expense that will be required to resolve this or any other lawsuit filed in connection with the Holdings Merger. We intend to vigorously defend against these lawsuits and any similar actions.

Each of the Israni, Lonergan and Fouke Complaints sought to enjoin the Holdings Merger transaction.

On November 15, 2010, Joel A. Gerber filed a class action and derivative complaint in the Court of Chancery of the State of Delaware. The complaint asserts claims against Holdings, EPGP, EPCO and the then directors of EPE Holdings for breach of express and implied duties in connection with Holdings' sale of TEPPCO GP to us in October 2009 (the "2009 Sale Transaction") and the Holdings Merger in November 2010. The complaint also asserts claims against Mr. Duncan's estate, EPCO and us for tortious interference and unjust enrichment in connection with the above transactions. The complaint alleges that Holdings sold TEPPCO GP to us in the 2009 Sale Transaction at an unfair price to Holdings and that the members of EPE Holdings' Audit, Conflicts and Governance ("ACG") Committee, which approved the 2009 Sale Transaction, were not independent because of their relationship with Mr. Duncan. The complaint also alleges that the terms of the Holdings Merger were unfair to Holdings' unitholders and that members of EPE Holdings' ACG committee, which approved the Holdings Merger, were not independent because of their relationship with Mr. Duncan. On December 13, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. In response to the motion to dismiss, on March 18, 2011, the plaintiff filed an amended complaint. On April 1, 2011, we filed a motion to dismiss the amended complaint with the Court of Chancery of the State of Delaware.

On March 8, 2011, Michael Crowley, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Michael Crowley v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC* (the "Crowley Complaint"). The Crowley Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners, that Duncan Energy Partners and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that we along with EPO have breached unspecified duties in connection with our proposal.

On March 11, 2011, Sanjay Israni, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Sanjay Israni v. Duncan Energy Partners L.P., DEP Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, Enterprise Products Operating LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell* (the "Israni Complaint II"). The Israni Complaint II alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners and that we along with all of the other named defendants aided and abetted in these alleged breaches of fiduciary duties.

On March 28, 2011, Michael Rubin, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Michael Rubin v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC* (the "Rubin Complaint"). The Rubin Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners, that Duncan Energy Partners and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that we along with EPO have breached unspecified duties in connection with our proposal.

On April 5, 2011, the plaintiffs in the Crowley Complaint, the Israni Complaint II, and the Rubin Complaint filed a Proposed Order of Consolidation and Appointment of Lead Counsel, which the Court granted on the same day consolidating the three actions into a single action, captioned *In re Duncan Energy Partners L.P. Unitholders Litigation*. We intend to vigorously defend against these lawsuits and any similar actions.

On March 7, 2011, Merle Davis, a purported unitholder of Duncan Energy Partners, filed a petition in the 269th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Merle Davis, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., W. Randall Fowler, Bryan F. Bulawa, William A.*

Bruckmann, III, Larry J. Casey, Richard S. Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P. (the "Davis Petition"). The Davis Petition alleges, among other things, that we and the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners and that we and Duncan Energy Partners aided and abetted in these alleged breaches of fiduciary duties.

On March 9, 2011, Donald Weilersbacher, a purported unitholder of Duncan Energy Partners, filed a petition in the 334th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Donald Weilersbacher, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., Enterprise Products Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell* (the "Weilersbacher Petition"). The Weilersbacher Petition alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners and that we aided and abetted in these alleged breaches of fiduciary duties.

On March 17, 2011, the plaintiffs in the Davis Petition and the Weilersbacher Petition filed a motion and proposed Order for Consolidation of Related Actions, Appointment of Interim Co-Lead Counsel, and Order Compelling Limited Expedited Discovery. Plaintiffs and defendants subsequently agreed to postpone discovery until after plaintiffs file a consolidated petition. On March 28, 2011, plaintiffs filed an amended motion and proposed Order for Consolidation of Related Actions and Appointment of Interim Co-Lead Counsel. We intend to vigorously defend against these lawsuits and any similar actions.

On February 14, 2008, Joel A. Gerber, then a purported unitholder of Holdings, filed a derivative complaint on behalf of Holdings in the Court of Chancery of the State of Delaware. The complaint names as defendants EPE Holdings, the Board of Directors of EPE Holdings, EPCO, and Dan L. Duncan and certain of his affiliates. Holdings is named as a nominal defendant. The complaint alleges that the defendants, in breach of their fiduciary duties to Holdings and its unitholders, caused Holdings to purchase in May 2007 the TEPPCO GP membership interests and TEPPCO units from Mr. Duncan's affiliates at an unfair price. The complaint also alleges that Charles E. McMahen, Edwin E. Smith and Thurmon Andress, then constituting the three members of EPE Holdings' ACG Committee, cannot be considered independent because of their relationships with Mr. Duncan. The complaint seeks relief (i) awarding damages for profits allegedly obtained by the defendants as a result of the alleged wrongdoings in the complaint and (ii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. Management believes this lawsuit is without merit and intends to vigorously defend against it. On April 11, 2008, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. In response to the motion to dismiss, on September 15, 2008, the plaintiff filed an amended complaint. On September 29, 2008, we filed a motion to dismiss the amended complaint with the Court of Chancery of the State of Delaware. The parties completed the briefing on the motion to dismiss on June 4, 2010. On February 8, 2011, the plaintiff filed a Motion for Leave to File a Second Amended and Supplemental Verified Complaint. On March 25, 2011, we filed a Brief in Opposition to Plaintiff's Motion for Leave to File a Second Amended and Supplemental Verified Complaint. See Note 12 for information regarding our relationship with EPCO and its affiliates.

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.

On April 23, 2010, the West Red Line of MAPL ruptured as a result of historical external, mechanical damage to the pipeline releasing 1,669 barrels of natural gasoline. 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 do not believe that any potential payment we make in connection with these releases will have a material impact on our consolidated financial position, results of operations or cash flows.

Redelivery Commitments

We store natural gas, NGLs and petrochemicals under various agreements that are owned by third parties. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At March 31, 2011, we had approximately 19.8 MMBbls of NGL and petrochemical products and 10.8 trillion British thermal units of natural gas in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposure. See Note 15 for information regarding insurance matters.

Regulatory Matters

Responding to scientific reports regarding threats posed by global warming, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located such as California and New Mexico, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content.

The U.S. Environmental Protection Agency ("EPA") has taken action under the federal Clean Air Act ("CAA") to regulate greenhouse gas emissions. In November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective.

These or other federal, regional and state measures could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities, and could by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources, adversely affect market demand or pricing for our products or products served by our midstream infrastructure. In addition, there have been several court cases implicating greenhouse gas emissions and climate change issues that could establish precedent that may indirectly affect our business, customers or the energy sector generally. All this, or any future such developments, may have an adverse effect on our business, financial position results of operations and cash flows.

Any of these climate change regulatory and legislative initiatives or litigation developments could have a material adverse effect on our business, financial position and results of operations.

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 AA and BB in January 2011 and (iii) the repayment of Senior Notes B in February 2011, there have been no significant changes in our consolidated debt obligations since those reported in our 2010 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Lease and rental expense included in costs and expenses was $20.5 million and $16.4 million during the three months ended March 31, 2011 and 2010, respectively. There have been no material changes in our operating lease commitments since those reported in our 2010 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2010 Form 10-K.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of March 31, 2011, our contingent claims against such parties were approximately $111 million and claims against us were approximately $96 million. 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 related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters have not been reflected in our consolidated financial statements.

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 $54.3 million in the event of a default by Centennial. As of March 31, 2011, we have a recorded liability of $7.6 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 March 31, 2011, we have a recorded liability of $3.3 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 15. Significant Risks and Uncertainties

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. 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 financial position, results of operations and cash flows. In addition, the proceeds of any insurance recovery 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. Typically, EPCO completes its annual insurance renewal process during the second quarter of each year.

Currently, EPCO's deductible for onshore physical damage from windstorms is $30.0 million per storm. EPCO's onshore insurance program currently provides $141.3 million of coverage per occurrence for named windstorm events. With respect to offshore Gulf of Mexico assets, the deductible for windstorm damage is $75.0 million per storm. EPCO's insurance program for offshore Gulf of Mexico assets currently provides $124.5 million of coverage in the aggregate. 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 is currently $5.0 million per occurrence.

For certain of our offshore assets, our producers 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.

With respect to onshore assets, we currently have business interruption coverage in connection with windstorms. We do not have any business interruption coverage for offshore Gulf of Mexico assets when the outage is due to a windstorm. However, 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 three months ended March 31, 2010. We did not receive any proceeds during the three months ended March 31, 2011.

Business interruption proceeds:	
Claims related to Hurricanes Gustav and Ike in 2008	$ 1.1
Total proceeds	1.1
Property damage proceeds:	
Claims related to Hurricanes Katrina and Rita in 2005	26.8
Claims related to Hurricanes Gustav and Ike in 2008	1.9
Other claims	0.3
Total proceeds	29.0
Total	$ 30.1

We recognize gains to the extent that we received cash proceeds from business interruption insurance claims. For the three months ended March 31, 2010, we recognized $1.1 million of such gains, which are a component of operating income and gross operating margin.

Property damage proceeds result from 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 $29.0 million related to such claims during the three months ended March 31, 2010. Operating income and gross operating margin for the three months ended March 31, 2010 include $7.9 million of gains.

On February 8, 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. The incident resulted in one fatality. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we have returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events is $5.0 million, which expense has been recorded in our earnings for the first quarter of 2011. Based on current information, we estimate that the total costs related to this incident will approximate $150 million.

At March 31, 2011, we had $20.3 million of estimated property damage insurance claims outstanding, including $12.8 million associated with the fire at West Storage.

Note 16. Supplemental Cash Flow Information

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

	For the Three Months Ended March 31, 2011	2010
Decrease (increase) in:		
Accounts receivable – trade	$ (81.2)	$ 43.4
Accounts receivable – related party	(8.1)	11.8
Inventories	357.2	(279.1)
Prepaid and other current assets	25.8	(55.3)
Other assets	(11.8)	0.6
Increase (decrease) in:		
Accounts payable – trade	28.0	118.6
Accounts payable – related party	5.7	(22.6)
Accrued product payables	(114.8)	302.5
Accrued interest	(71.6)	(54.3)
Other current liabilities	(9.3)	11.1
Other liabilities	0.1	(3.3)
Net effect of changes in operating accounts	$ 120.0	$ 73.4

We incurred liabilities for construction in progress that had not been paid at March 31, 2011 and December 31, 2010 of $207.7 million and $201.6 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.

Proceeds from asset sales and related transactions increased $62.5 million quarter-to-quarter, primarily from sales of certain marine assets and a fractionation facility during the first quarter of 2011.

See Note 10 for information regarding cash amounts attributable to noncontrolling interests.

See Note 15 for information regarding cash proceeds from insurance claims.

Note 17. 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 and its consolidated subsidiaries. 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 9 for additional information regarding our consolidated debt obligations.

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
March 31, 2011

	EPO and Subsidiaries				
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Pro Partners L.P. (Guaranto**
ASSETS					
Current assets:					
Cash and cash equivalents and restricted cash	$ 290.0	$ 62.4	$ (10.4)	$ 342.0	$
Accounts receivable – trade, net	1,510.1	2,400.0	(28.8)	3,881.3	
Accounts receivable – related parties	(1,164.5)	1,139.3	64.8	39.6	
Prepaid and other current assets	791.7	410.7	(10.3)	1,192.1	
Total current assets	1,427.3	4,012.4	15.3	5,455.0	
Property, plant and equipment, net	1,465.7	18,437.1	(9.9)	19,892.9	
Investments in unconsolidated affiliates	23,077.6	6,349.9	(27,157.6)	2,269.9	
Intangible assets, net	152.2	1,656.1	(14.3)	1,794.0	
Goodwill	469.1	1,638.6	--	2,107.7	
Other assets	303.4	141.5	(135.0)	309.9	
Total assets	$ 26,895.3	$ 32,235.6	$ (27,301.5)	$ 31,829.4	$
LIABILITIES AND EQUITY					
Current liabilities:					
Current maturities of debt	$ 490.5	$ 291.8	$ --	$ 782.3	$
Accounts payable – trade	209.4	408.6	(10.4)	607.6	
Accounts payable – related parties	--	200.9	(61.9)	139.0	
Accrued product payables	1,676.5	2,434.0	(31.8)	4,078.7	
Accrued interest	179.6	1.8	(0.1)	181.3	
Other current liabilities	254.6	420.2	(5.7)	669.1	
Total current liabilities	2,810.6	3,757.3	(109.9)	6,458.0	
Long-term debt	12,556.1	726.4	(8.9)	13,273.6	
Other long-term liabilities	34.6	256.2	(0.4)	290.4	
Commitments and contingencies					
Equity:					
Partners' and other owners' equity	11,494.0	26,611.4	(26,834.8)	11,270.6	
Noncontrolling interest	--	884.3	(347.5)	536.8	
Total equity	11,494.0	27,495.7	(27,182.3)	11,807.4	
Total liabilities and equity	$ 26,895.3	$ 32,235.6	$ (27,301.5)	$ 31,829.4	$

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2010

	EPO and Subsidiaries				
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Pro Partners L.P. (Guarantor
ASSETS					
Current assets:					
Cash and cash equivalents and restricted cash	$ 97.1	$ 70.0	$ (2.9)	$ 164.2	$
Accounts receivable – trade, net	1,684.1	2,127.9	(11.9)	3,800.1	
Accounts receivable – related parties	(952.7)	927.6	63.2	38.1	
Prepaid and other current assets	1,030.7	486.2	(10.9)	1,506.0	
Total current assets	1,859.2	3,611.7	37.5	5,508.4	
Property, plant and equipment, net	1,461.0	17,881.9	(10.0)	19,332.9	
Investments in unconsolidated affiliates	22,640.3	6,254.0	(26,601.2)	2,293.1	
Intangible assets, net	155.5	1,700.8	(14.6)	1,841.7	
Goodwill	469.1	1,638.6	--	2,107.7	
Other assets	296.4	126.7	(144.8)	278.3	
Total assets	$ 26,881.5	$ 31,213.7	$ (26,733.1)	$ 31,362.1	$
LIABILITIES AND EQUITY					
Current liabilities:					
Current maturities of debt	$ --	$ 282.3	$ --	$ 282.3	$
Accounts payable – trade	138.1	406.8	(2.9)	542.0	
Accounts payable – related parties	--	204.3	(71.2)	133.1	
Accrued product payables	2,057.2	2,124.8	(17.2)	4,164.8	
Accrued interest	251.3	1.8	(0.2)	252.9	
Other current liabilities	217.2	294.7	(6.9)	505.0	
Total current liabilities	2,663.8	3,314.7	(98.4)	5,880.1	
Long-term debt	12,663.7	626.4	(8.9)	13,281.2	
Other long-term liabilities	48.0	251.5	(0.1)	299.4	
Commitments and contingencies					
Equity:					
Partners' and other owners' equity	11,506.0	23,176.8	(23,321.2)	11,361.6	
Noncontrolling interest	--	3,844.3	(3,304.5)	539.8	
Total equity	11,506.0	27,021.1	(26,625.7)	11,901.4	
Total liabilities and equity	$ 26,881.5	$ 31,213.7	$ (26,733.1)	$ 31,362.1	$

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 March 31, 2011

	EPO and Subsidiaries				
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)
Revenues	$ 8,324.8	$ 6,078.7	$ (4,219.8)	$ 10,183.7	$ --
Costs and expenses:					
Operating costs and expenses	8,178.2	5,578.6	(4,219.7)	9,537.1	--
General and administrative costs	0.9	33.7	--	34.6	3.3
Total costs and expenses	8,179.1	5,612.3	(4,219.7)	9,571.7	3.3
Equity in income of unconsolidated affiliates	458.0	31.8	(473.6)	16.2	424.0
Operating income	603.7	498.2	(473.7)	628.2	420.7
Other income (expense):					
Interest expense	(179.0)	(6.7)	1.9	(183.8)	--
Other, net	2.0	0.4	(1.9)	0.5	--
Total other expense, net	(177.0)	(6.3)	--	(183.3)	--
Income before provision for income taxes	426.7	491.9	(473.7)	444.9	420.7
Provision for income taxes	(2.8)	(4.3)	--	(7.1)	--
Net income	423.9	487.6	(473.7)	437.8	420.7
Net loss (income) attributable to noncontrolling interest	--	(3.4)	(10.7)	(14.1)	--
Net income attributable to entity	$ 423.9	$ 484.2	$ (484.4)	$ 423.7	$ 420.7

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2010

	EPO and Subsidiaries				
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)
Revenues	$ 6,957.4	$ 4,613.0	$ (3,025.9)	$ 8,544.5	$ --
Costs and expenses:					
Operating costs and expenses	6,846.1	4,152.3	(3,026.5)	7,971.9	--
General and administrative costs	--	35.6	--	35.6	2.0
Total costs and expenses	6,846.1	4,187.9	(3,026.5)	8,007.5	2.0
Equity in income of unconsolidated affiliates	413.7	53.5	(451.2)	16.0	379.8
Operating income	525.0	478.6	(450.6)	553.0	377.8
Other income (expense):					
Interest expense	(143.8)	(7.4)	2.6	(148.6)	--
Other, net	2.8	(0.1)	(2.6)	0.1	--
Total other expense, net	(141.0)	(7.5)	--	(148.5)	--
Income before provision for income taxes	384.0	471.1	(450.6)	404.5	377.8
Provision for income taxes	(4.9)	(3.8)	--	(8.7)	--
Net income	379.1	467.3	(450.6)	395.8	377.8
Net loss (income) attributable to noncontrolling interest	--	0.2	(16.3)	(16.1)	--
Net income attributable to entity	$ 379.1	$ 467.5	$ (466.9)	$ 379.7	$ 377.8

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 2011

	EPO and Subsidiaries				
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Product Partners L.P. (Guarantor)**
Operating activities:					
Net income	$ 423.9	$ 487.6	$ (473.7)	$ 437.8	$ 42
Adjustments to reconcile net income to cash provided by operating activities:					
Depreciation, amortization and accretion	27.8	213.6	(0.3)	241.1	
Equity in income of unconsolidated affiliates	(458.0)	(31.8)	473.6	(16.2)	(42
Distributions received from unconsolidated affiliates	65.5	56.1	(79.1)	42.5	48
Net effect of changes in operating accounts and other operating activities	455.1	(275.3)	(85.3)	94.5	
Cash provided by operating activities	514.3	450.2	(164.8)	799.7	48
Investing activities:					
Capital expenditures, net of contributions in aid of construction costs	(24.9)	(685.4)	--	(710.3)	
Other investing activities	(309.5)	79.0	214.4	(16.1)	(2
Cash used in investing activities	(334.4)	(606.4)	214.4	(726.4)	(2
Financing activities:					
Borrowings under debt agreements	2,662.1	159.5	--	2,821.6	
Repayments of debt	(2,266.0)	(50.0)	--	(2,316.0)	
Cash distributions paid to partners	(481.7)	(132.8)	132.8	(481.7)	(47
Cash distributions paid to noncontrolling interest	--	(41.7)	24.5	(17.2)	
Cash contributions from noncontrolling interest	--	214.3	(213.0)	1.3	
Net cash proceeds from issuance of common units	--	--	--	--	2
Cash contributions from members	22.1	1.4	(1.4)	22.1	
Other financing activities	(18.5)	--	--	(18.5)	(
Cash provided by (used in) financing activities	(82.0)	150.7	(57.1)	11.6	(46
Net change in cash and cash equivalents	97.9	(5.5)	(7.5)	84.9	
Cash and cash equivalents, January 1	0.5	67.9	(2.9)	65.5	
Cash and cash equivalents, March 31	$ 98.4	$ 62.4	$ (10.4)	$ 150.4	$

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 2010

	EPO and Subsidiaries				
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)
Operating activities:					
Net income	$ 379.1	$ 467.3	$ (450.6)	$ 395.8	$ 377.8
Adjustments to reconcile net income to cash provided by operating activities:					
Depreciation, amortization and accretion	21.5	196.4	(0.3)	217.6	--
Equity in income of unconsolidated affiliates	(413.7)	(53.5)	451.2	(16.0)	(379.8)
Distributions received from unconsolidated affiliates	47.7	44.4	(61.9)	30.2	406.8
Net effect of changes in operating accounts and other operating activities	427.2	(429.6)	61.7	59.3	2.1
Cash provided by operating activities	461.8	225.0	0.1	686.9	406.9
Investing activities:					
Capital expenditures, net of contributions in aid of construction costs	(18.0)	(326.2)	--	(344.2)	--
Cash used for business combinations	(2.2)	--	--	(2.2)	--
Other investing activities	(166.4)	57.8	84.5	(24.1)	(437.1)
Cash used in investing activities	(186.6)	(268.4)	84.5	(370.5)	(437.1)
Financing activities:					
Borrowings under debt agreements	330.4	15.1	--	345.5	--
Repayments of debt	(579.9)	(15.1)	--	(595.0)	--
Cash distributions paid to partners	(406.8)	(49.1)	49.1	(406.8)	(407.3)
Cash distributions paid to noncontrolling interest	--	(32.8)	15.3	(17.5)	--
Cash contributions from noncontrolling interest	--	78.8	(78.6)	0.2	--
Net cash proceeds from issuance of common units	--	--	--	--	437.7
Cash contributions from members	437.1	68.6	(68.6)	437.1	--
Other financing activities	(0.1)	--	--	(0.1)	(0.2)
Cash provided by (used in) financing activities	(219.3)	65.5	(82.8)	(236.6)	30.2
Effect of exchange rate changes on cash	--	0.4	--	0.4	--
Net change in cash and cash equivalents	55.9	22.1	1.8	79.8	--
Cash and cash equivalents, January 1	14.4	46.3	(6.2)	54.5	--
Cash and cash equivalents, March 31	$ 70.3	$ 68.8	$ (4.4)	$ 134.7	$ --

Note 18. Subsequent Event

Agreement and Plan of Merger with Duncan Energy Partners

On April 28, 2011, we, our general partner and two of our subsidiaries entered into a definitive merger agreement with Duncan Energy Partners and DEP GP. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

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

For the three months ended March 31, 2011 and 2010.

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, 2010 (the "2010 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," "Enterprise" 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, and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see "Basis for Financial Statement Presentation" within this Item 2.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which 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 and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P. (NYSE: DEP), which is a consolidated subsidiary of EPO. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and a wholly owned subsidiary of EPO. See "Significant Recent Developments" included under this Item 2 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

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. (NYSE: ETE) and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”) and Regency Energy Partners LP (“RGNC”). The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). We own noncontrolling interests in Energy Transfer Equity, which we account for using the equity method of accounting.

Duncan Energy Partners and Energy Transfer Equity electronically file certain documents with the U.S. Securities and Exchange Commission (“SEC”), including annual reports on Form 10-K and quarterly reports on Form 10-Q. The SEC maintains an Internet website at www.sec.gov that contains periodic reports and other information regarding these registrants.

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 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 2010 Form 10-K. 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 and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain 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 approximately 50,200 miles of onshore and offshore pipelines; 190 MMBbls of storage capacity for NGLs, refined products and crude oil; and 27 Bcf of natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation 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 services; 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 six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP owns a non-economic general partner interest in us.

Basis of Financial Statement Presentation

In accordance with rules and regulations of the U.S. Securities and Exchange Commission ("SEC") and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of financial information of businesses that we control (e.g., Duncan Energy Partners). Our general purpose consolidated financial statements present those investments over which we do not have control as unconsolidated affiliates (e.g., our equity method investment in Energy Transfer Equity). Noncontrolling interest reflects third-party and related party ownership of our consolidated subsidiaries.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger results in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise Products Partners L.P. is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). While it was a publicly traded partnership, Holdings (NYSE: EPE) electronically filed its annual and quarterly consolidated financial statements with the SEC. You can access this information at www.sec.gov.

The primary differences between Holdings' and Enterprise's consolidated results of operations were (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interest. See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our noncontrolling interests.

Historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding earnings per unit.

Significant Recent Developments

The following information highlights significant developments since January 1, 2011 through the date of this filing (May 10, 2011), 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.

Enterprise to Extend Eagle Ford Shale Crude Oil Pipeline System

On May 3, 2011, we announced plans to build an 80-mile extension of our 350 MBPD Eagle Ford Shale crude oil pipeline, which would allow us to serve growing production areas in the southwestern portion of the supply basin. The Phase II project, which is being designed with a capacity of 200 MBPD, would originate in Wilson County, Texas at the terminus of our previously announced 140-mile Phase I segment, and extend to a site near Gardendale, Texas in La Salle County, where a new central delivery point is planned for construction that will feature 500,000 barrels of storage. Phase I is projected to begin service by the second quarter of 2012, with Phase II set to commence operations in the first quarter of 2013. When completed, the approximately 220-mile crude oil pipeline system will provide Eagle Ford Shale producers with access to the Texas Gulf Coast refining complex through our integrated midstream network.

Enterprise and ETP to form pipeline joint venture

On April 26, 2011, we announced an agreement with ETP to form a 50/50 joint venture to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. The project would allow greater access to the U.S. Gulf Coast-area refining complex and add approximately 500,000 barrels of storage capacity at new facilities to be constructed and owned by the joint venture at our Houston crude oil terminal. The pipeline would provide an outlet for more than 400 MBPD of crude oil supplies which are currently stranded at the Cushing hub and priced at a substantial discount to imported crude oil on the Gulf Coast. The pipeline would also give refiners on the Gulf Coast improved access to growing supplies of domestic crude oil production and an alternative to higher priced crude oil imports, which represent their largest source of supply. The new pipeline is expected to begin service in the fourth quarter of 2012. The joint venture partners will share commercial responsibilities, with an integrated project team responsible for construction of the pipeline and Enterprise serving as operator.

Expansion of Houston Ship Channel Import/Export Terminal

On March 29, 2011, we announced the expansion of our import/export terminal on the Houston Ship Channel. The expansion project is expected to nearly double the fully refrigerated export loading capacity for propane and other NGLs at the facility to more than 10,000 barrels per hour, while enhancing its ability to load multiple vessels simultaneously. We expect to complete the expansion in the second half of 2012.

Agreement and Plan of Merger with Duncan Energy Partners

On April 28, 2011, we entered into an Agreement and Plan of Merger, dated as of April 28, 2011 (the “Duncan Merger Agreement”), by and among Enterprise, Enterprise GP, EPD MergerCo LLC (“Duncan MergerCo,” a Delaware limited liability company and a wholly owned subsidiary of Enterprise), Duncan Energy Partners and DEP GP. At the effective time of the merger, Duncan MergerCo will merge with and into Duncan Energy Partners, pursuant to the Duncan Merger Agreement, with Duncan Energy Partners surviving the merger as a wholly owned subsidiary of Enterprise (the “Duncan Merger”), and all of the outstanding Duncan Energy Partners common units at the effective time of the merger will be cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange rate of 1.01 Enterprise common units for each Duncan Energy Partners common unit.

The Duncan Merger Agreement and the Duncan Merger must be approved by the affirmative vote or consent of holders of (i) a majority of the outstanding common units of Duncan Energy Partners and (ii) a majority of the Duncan Energy Partners common units owned by the Duncan Unaffiliated Unitholders (as defined in the Duncan Merger Agreement) that actually vote for or against such approval. In connection with the Duncan Merger Agreement, we, Duncan Energy Partners and Enterprise GTM Holdings L.P., a Delaware limited partnership and a wholly owned subsidiary of Enterprise (“Enterprise GTM”), entered into a Voting Agreement, dated as of April 28, 2011 (the “Voting Agreement”), pursuant to which Enterprise GTM and Enterprise agreed to vote any of the Duncan Energy Partners common units owned by them or their subsidiaries in favor of the adoption of the Duncan Merger Agreement and the Duncan Merger at any meeting of the Duncan Energy Partners unitholders, including the 33,783,587 Duncan Energy Partners common units currently directly owned by Enterprise GTM (representing approximately 58.5% of the outstanding common units of Duncan Energy Partners). The Voting Agreement will terminate upon the termination of the Duncan Merger Agreement.

The Duncan Merger Agreement contains customary representations, warranties and covenants by each of the parties. Completion of the Duncan Merger is conditioned upon, among other things: (i) requisite Duncan Energy Partners unitholder approval of the Duncan Merger Agreement and the Duncan Merger; (ii) applicable regulatory approvals; (iii) the absence of certain legal injunctions or impediments prohibiting the transactions; (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance by Enterprise of the Enterprise common units in connection with the Duncan Merger; (v) the receipt of certain tax opinions; and (vi) approval for the listing of the Enterprise common units issued in connection /with the Duncan Merger on the NYSE.

Incident at Mont Belvieu Storage Facility

On February 8, 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. The incident resulted in one fatality. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we have returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events is $5.0 million, which expense has been recorded in our earnings for the first quarter of 2011. Based on current information, we estimate that the total costs related to this incident will approximate $150 million.

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 presented:

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)
2010					
1st Quarter	$ 5.30	$ 0.73	$ 1.24	$ 1.52	$ 1.64
2nd Quarter	$ 4.09	$ 0.55	$ 1.08	$ 1.47	$ 1.58
3rd Quarter	$ 4.38	$ 0.48	$ 1.07	$ 1.38	$ 1.43
4th Quarter	$ 3.80	$ 0.64	$ 1.26	$ 1.62	$ 1.68
2010 Averages	$ 4.39	$ 0.60	$ 1.16	$ 1.50	$ 1.58
2011					
1st Quarter	$ 4.11	$ 0.66	$ 1.37	$ 1.75	$ 1.85

(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 produ
(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 presented. 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 March 31,	
	2011	**2010**
NGL Pipelines & Services, net:		
NGL transportation volumes (MBPD)	2,366	2,240
NGL fractionation volumes (MBPD)	549	473
Equity NGL production (MBPD)	119	122
Fee-based natural gas processing (MMcf/d)	3,698	2,679
Onshore Natural Gas Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	11,678	10,706
Onshore Crude Oil Pipelines & Services, net:		
Crude oil transportation volumes (MBPD)	666	672
Offshore Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	1,155	1,406
Crude oil transportation volumes (MBPD)	299	354
Platform natural gas processing (MMcf/d)	445	632
Platform crude oil processing (MBPD)	16	18
Petrochemical & Refined Products Services, net:		
Butane isomerization volumes (MBPD)	88	73
Propylene fractionation volumes (MBPD)	73	80
Octane enhancement production volumes (MBPD)	12	11
Transportation volumes, primarily refined products and petrochemicals (MBPD)	743	804
Total, net:		
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	4,074	4,070
Natural gas transportation volumes (BBtus/d)	12,833	12,112
Equivalent transportation volumes (MBPD) (1)	7,451	7,257

(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 presented (dollars in millions):

	For the Three Months Ended March 31,	
	2011	**2010**
Revenues	$ 10,183.7	$ 8,544.5
Operating costs and expenses	9,537.1	7,971.9
General and administrative costs	37.9	40.3
Equity in income of unconsolidated affiliates	16.2	26.6
Operating income	624.9	558.9
Interest expense	183.8	157.9
Provision for income taxes	7.1	8.7
Net income	434.5	392.4
Net income attributable to noncontrolling interest	13.8	322.5
Net income attributable to partners	420.7	69.9

For information regarding amounts attributable to noncontrolling interest, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
NGL Pipelines & Services	$ 504.4	$ 437.3
Onshore Natural Gas Pipelines & Services	159.2	130.3
Onshore Crude Oil Pipelines & Services	31.8	26.7
Offshore Pipelines & Services	61.3	81.1
Petrochemical & Refined Products Services	112.4	120.0
Other Investments	6.3	10.6
Total segment gross operating margin	$ 875.4	$ 806.0

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 11 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 presented (dollars in millions):

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
NGL Pipelines & Services:		
Sales of NGLs	$ 4,057.1	$ 3,664.1
Sales of other petroleum and related products	0.6	0.5
Midstream services	199.1	181.7
Total	4,256.8	3,846.3
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	712.7	975.2
Midstream services	203.9	186.3
Total	916.6	1,161.5
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	3,348.2	2,367.3
Midstream services	22.4	19.3
Total	3,370.6	2,386.6
Offshore Pipelines & Services:		
Sales of natural gas	0.3	0.4
Sales of crude oil	3.3	2.1
Midstream services	60.8	86.1
Total	64.4	88.6
Petrochemical & Refined Products Services:		
Sales of other petroleum and related products	1,382.8	932.6
Midstream services	192.5	128.9
Total	1,575.3	1,061.5
Total consolidated revenues	$ 10,183.7	$ 8,544.5

Comparison of Three Months Ended March 31, 2011 with Three Months Ended March 31, 2010

Revenues for the first quarter of 2011 were $10.18 billion compared to $8.54 billion for the first quarter of 2010, a $1.64 billion quarter-to-quarter increase. Higher volumes and, with the exception of natural gas, higher energy commodity sales prices during the first quarter of 2011 compared to the first quarter of 2010 resulted in a $1.56 billion quarter-to-quarter increase in consolidated revenues from the sale of NGLs, natural gas, crude oil and petrochemical and refined products. Consolidated revenues from the sale of NGLs increased $393.0 million quarter-to-quarter primarily due to higher sales prices during the first quarter of 2011 compared to the first quarter of 2010. Revenues from the sale of natural gas decreased $262.6 million quarter-to-quarter primarily due to lower sales prices. Crude oil sales revenues increased $982.1 million quarter-to-quarter attributable to both higher sales prices and volumes. Consolidated revenues from the sale of other petroleum and related products increased $450.3 million quarter-to-quarter primarily due to higher propylene and refined products sales prices during the first quarter of 2011 compared to the first quarter of 2010. Collectively, the remainder of our consolidated revenues increased $76.4 million quarter-to-quarter primarily due to revenues generated from businesses we acquired or assets we constructed and placed into service since the first quarter of 2010, principally the State Line and Fairplay natural gas gathering systems we acquired in May 2010 and a trucking business we acquired from EPCO in September 2010.

Operating costs and expenses were $9.54 billion for the first quarter of 2011 compared to $7.97 billion for the first quarter of 2010, a $1.57 billion quarter-to-quarter increase. The cost of sales of our marketing activities increased $1.28 billion quarter-to-quarter primarily due to higher sales volumes and, with the exception of natural gas, higher energy commodity prices. The operating costs and expenses of our natural gas processing plants increased $159.2 million quarter-to-quarter primarily due to higher NGL prices in the first quarter of 2011 relative to the first quarter of 2010, which resulted in higher operating costs associated with percent-of-proceeds and margin-band processing contracts. Operating costs and expenses increased approximately $71.0 million quarter-to-quarter attributable to businesses we acquired or assets we constructed and placed into service since the first quarter of 2010. In the aggregate, the remainder of our consolidated operating costs and expenses increased $54.1 million quarter-to-quarter primarily due to an increase in depreciation and amortization expenses attributable to newly acquired or constructed assets. General and administrative costs decreased $2.4 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. For example, higher energy commodity prices result in an increase in revenues attributable to the sale of NGLs, crude oil and petrochemical and refined products; however, these same higher energy commodity prices also increase the associated cost of sales as purchase prices rise. The weighted-average indicative market price for NGLs was $1.36 per gallon during the first quarter of 2011 versus $1.23 per gallon during the first quarter of 2010 – an 11% quarter-to-quarter increase. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.11 per MMBtu during the first quarter of 2011 versus $5.30 per MMBtu during the first quarter of 2010 – a 22% quarter-to-quarter decrease. The market price of crude oil (as measured on the NYMEX) averaged $94.10 per barrel during the first quarter of 2011 compared to $78.72 per barrel during the first quarter of 2010 – a 20% quarter-to-quarter increase. See "Selected Price and Volumetric Data" included within this Item 2 for additional historical energy commodity pricing information.

Equity earnings from our unconsolidated affiliates were $16.2 million for the first quarter of 2011 compared to $26.6 million for the first quarter of 2010. The quarter-to-quarter decrease in equity earnings is primarily due to lower throughput volumes during the first quarter of 2011 compared to the first quarter of 2010 on the pipeline assets owned by Seaway Crude Pipeline Company ("Seaway"), Centennial Pipeline LLC ("Centennial") and our investees operating in the Gulf of Mexico. In addition, equity earnings from Energy Transfer Equity decreased quarter-to-quarter as discussed below.

Operating income for the first quarter of 2011 was $624.9 million compared to $558.9 million for the first quarter of 2010. Collectively, the changes in revenues, costs and expenses and equity in income of unconsolidated affiliates described above resulted in the $66.0 million quarter-to-quarter increase in operating income.

Interest expense increased to $183.8 million for the first quarter of 2011 from $157.9 million for the first quarter of 2010, a $25.9 million quarter-to-quarter increase. The increase in interest expense is primarily due to EPO's issuance of Senior Notes X, Y and Z in May 2010 and Senior Notes AA and BB in

January 2011. Average debt principal outstanding increased to $14.11 billion during the first quarter of 2011 from $12.26 billion during the first quarter of 2010.

Provision for income taxes decreased $1.6 million quarter-to-quarter due in part to lower expenses associated with the Texas Margin Tax.

As a result of items noted in the previous paragraphs, our consolidated net income increased $42.1 million quarter-to-quarter to $434.5 million for the first quarter of 2011 compared to $392.4 million for the first quarter of 2010. Net income attributable to noncontrolling interests was $13.8 million for the first quarter of 2011 compared to $322.5 million for the first quarter of 2010. For periods prior to the Holdings Merger, that portion of the income of Enterprise attributable to its limited partner interests owned by third parties and related parties other than Holdings is included in net income attributable to noncontrolling interests. Net income attributable to noncontrolling interest for the first quarter of 2010 includes $306.5 million attributable to the limited partners of Enterprise. See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our net income attributable to noncontrolling interests. Net income attributable to partners increased $350.8 million quarter-to-quarter to $420.7 million for the first quarter of 2011 compared to $69.9 million for the first quarter of 2010.

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 $504.4 million for the first quarter of 2011 compared to $437.3 million for the first quarter of 2010, a $67.1 million quarter-to-quarter increase.

Gross operating margin from our natural gas processing and related NGL marketing business was $277.7 million for the first quarter of 2011 compared to $259.7 million for the first quarter of 2010, an $18.0 million quarter-to-quarter increase. Gross operating margin from our NGL marketing activities increased $17.2 million quarter-to-quarter due to higher sales volumes and margins. Our Rocky Mountains natural gas processing plants contributed $5.9 million of the quarter-to-quarter increase in gross operating margin primarily due to higher equity NGL production and fee-based processing volumes at our Meeker facility during the first quarter of 2011 compared to the first quarter of 2010. Gross operating margin for the first quarter of 2011 includes $3.8 million attributable to natural gas processing activities on the Fairplay system, which we acquired in May 2010. Collectively, gross operating margin from the remainder of our natural gas processing activities decreased $8.9 million quarter-to-quarter primarily due to lower equity NGL production volumes in Texas and higher maintenance expenses at our Chaco facility during the first quarter of 2011 compared to the first quarter of 2010.

Gross operating margin from our NGL pipelines and related storage business was $179.9 million for the first quarter of 2011 compared to $150.1 million for the first quarter of 2010, a $29.8 million quarter-to-quarter increase. Total NGL transportation volumes increased to 2,366 MBPD during the first quarter of 2011 from 2,240 MBPD during the first quarter of 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals increased $11.6 million quarter-to-quarter primarily due to higher transportation revenues resulting from an increase in volumes delivered under higher tariffs during the first quarter of 2011 compared to the first quarter of 2010. Collectively, gross operating margin from our Louisiana Pipeline System and Lou-Tex NGL Pipeline increased $6.3 million quarter-to-quarter primarily due to a 77 MBPD increase in throughput volumes. Gross operating margin from our NGL storage activities increased $5.9 million quarter-to-quarter. A quarter-to-quarter increase in revenues due to higher storage volumes and fees at our facility in Mont Belvieu, Texas and higher fees charged for NGL storage and terminaling services provided to customers primarily in the northeastern U.S. was partially offset by $5.0 million of property damage repair expenses in the first quarter of 2011 resulting from a fire that occurred at the West Storage location of our Mont Belvieu facility. Gross operating margin from the remainder of our NGL pipelines and related storage business increased $6.0 million quarter-to-quarter primarily due to lower operating expenses associated with net operational measurement and well gains during the first quarter of 2011 compared to the first quarter of 2010.

See "Significant Recent Developments" within this Item 2 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

Gross operating margin from our NGL fractionation business was $46.8 million for the first quarter of 2011 compared to $27.5 million for the first quarter of 2010, a $19.3 million quarter-to-quarter increase. Our NGL fractionation volumes were 549 MBPD during the first quarter of 2011 compared to 473 MBPD during the first quarter of 2010. Gross operating margin from our Mont Belvieu NGL fractionation facility increased $18.6 million quarter-to-quarter primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we added 75 MBPD of NGL fractionation capacity with the completion of a fourth NGL fractionator at our complex in Mont Belvieu, Texas. Collectively, gross operating margin from the remainder of our NGL fractionation business increased $0.7 million quarter-to-quarter.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $159.2 million for the first quarter of 2011 compared to $130.3 million for the first quarter of 2010, a $28.9 million quarter-to-quarter increase. Our onshore natural gas transportation volumes were 11.68 TBtus/d during the first quarter of 2011 compared to 10.71 TBtus/d during the first quarter of 2010.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $146.0 million for the first quarter of 2011 compared to $116.0 million for the first quarter of 2010, a $30.0 million quarter-to-quarter increase. Gross operating margin for the first quarter of 2011 includes $14.8 million attributable to the State Line and Fairplay natural gas gathering systems, which we acquired in May 2010. Gross operating margin from our Texas Intrastate System increased $9.4 million quarter-to-quarter primarily due to increased natural gas volumes from the Eagle Ford Shale supply basin, which resulted in strong demand for our natural gas transportation services during the first quarter of 2011. Gross operating margin from the remainder of our onshore natural gas pipelines and related marketing business increased $5.8 million quarter-to-quarter primarily due to higher natural gas sales margins associated with our marketing activities.

Gross operating margin from our natural gas storage business was $13.2 million for the first quarter of 2011 compared to $14.3 million for the first quarter of 2010. The $1.1 million quarter-to-quarter decrease in gross operating margin is primarily due to less demand for interruptible natural gas storage services during the first quarter of 2011 compared to the first quarter of 2010.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $31.8 million for the first quarter of 2011 compared to $26.7 million for the first quarter of 2010, a $5.1 million quarter-to-quarter increase. Total onshore crude oil transportation volumes were 666 MBPD during the first quarter of 2011 compared to 672 MBPD during the first quarter of 2010. Gross operating margin from our crude oil marketing and related activities increased $5.5 million quarter-to-quarter primarily due to higher sales volumes and margins. Our crude oil marketing activities benefited from higher crude oil production during the first quarter of 2011 compared to the first quarter of 2010 in the Eagle Ford Shale, Barnett Shale and West Texas supply basins. Gross operating margin from our Red River pipeline system increased $2.7 million quarter-to-quarter primarily due to higher throughput volumes and lower operating expenses during the first quarter of 2011 compared to the first quarter of 2010. Equity earnings from our investment in Seaway decreased $2.9 million quarter-to-quarter primarily due to lower volumes delivered to Cushing, Oklahoma from the Texas Gulf Coast during the first quarter of 2011 compared to the first quarter of 2010. Net to our interest, throughput volumes on the pipeline system owned by Seaway decreased 49 MBPD quarter-to-quarter. Collectively, gross operations from the remainder of our onshore crude oil businesses decreased $0.2 million quarter-to-quarter.

Offshore Pipelines & Services. Gross operating margin from this business segment was $61.3 million for the first quarter of 2011 compared to $81.1 million for the first quarter of 2010, a $19.8 million quarter-to-quarter decrease. Results for the first quarter of 2010 include $9.0 million of gains related to insurance proceeds. Excluding the effects of insurance proceeds, gross operating margin from this business segment decreased $10.8 million quarter-to-quarter. The following paragraphs provide a discussion of segment results excluding insurance-related gains.

In general, natural gas and crude oil drilling activity in the Gulf of Mexico ceased as a result of the federal offshore drilling moratorium, which went into effect in May 2010. This resulted in lower throughput volumes available to certain of our offshore pipeline and platform assets. The moratorium was lifted in October 2010. Although crude oil and natural gas drilling activity has resumed on a limited basis, certain of our offshore pipeline and platform assets continued to experience reduced throughput volumes during the first quarter of 2011, as existing wells experience natural declines. The pace of drilling activity in the Gulf of Mexico remains uncertain.

Gross operating margin from our offshore crude oil pipeline business was $20.5 million for the first quarter of 2011 compared to $25.3 million for the first quarter of 2010, a $4.8 million quarter-to-quarter decrease. Total offshore crude oil transportation volumes averaged 299 MBPD during the first quarter of 2011 compared to 354 MBPD during the first quarter of 2010. Collectively, equity earnings from our investments in Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”) and Cameron Highway Oil Pipeline Company (“Cameron Highway”) decreased $3.0 million quarter-to-quarter primarily due to lower throughput volumes. Net to our interest, crude oil throughput volumes on the pipeline assets owned by Poseidon and Cameron Highway decreased 38 MBPD quarter-to-quarter. In addition, gross operating margin from our Shenzi and Constitution crude oil pipelines decreased $2.3 million quarter-to-quarter primarily due to a 36 MBPD decrease in transportation volumes. Collectively, gross operating margin from the remainder of our offshore crude oil pipeline business increased $0.5 million quarter-to-quarter primarily due to lower operating costs and expenses during the first quarter of 2011 compared to the first quarter of 2010.

Gross operating margin from our offshore natural gas pipeline business was $10.7 million for the first quarter of 2011 compared to $11.9 million for the first quarter of 2010, a $1.2 million quarter-to-quarter decrease. Total offshore natural gas transportation volumes were 1,155 BBtus/d during the first quarter of 2011 versus 1,406 BBtus/d during the first quarter of 2010. Gross operating margin from our Independence Trail pipeline decreased $5.2 million quarter-to-quarter primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 511 BBtus/d during the first quarter of 2011 from 717 BBtus/d during the first quarter of 2010 as a result of well depletion and lost production (i.e., wells that were shut-in or watered-out) and indirect impacts of the federal offshore drilling moratorium. Collectively, gross operating margin from the remainder of our offshore natural gas pipeline business increased $4.0 million quarter-to-quarter primarily due to lower operating expenses on our Viosca Knoll Gathering System and High Island Offshore System during the first quarter of 2011 compared to the first quarter of 2010.

Gross operating margin from our offshore platform services business was $30.1 million for the first quarter of 2011 compared to $34.9 million for the first quarter of 2010, a $4.8 million quarter-to-quarter decrease. Our net platform natural gas processing volumes were 445 MMcf/d during the first quarter of 2011 compared to 632 MMcf/d during the first quarter of 2010. The quarter-to-quarter decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform as a result of well depletion and lost production (i.e., wells that were shut-in or watered-out) and indirect impacts of the federal offshore drilling moratorium.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $112.4 million for the first quarter of 2011 compared to $120.0 million for the first quarter of 2010, a $7.6 million quarter-to-quarter decrease.

Gross operating margin from propylene fractionation and related activities was $48.8 million for the first quarter of 2011 compared to $43.1 million for the first quarter of 2010, a $5.7 million quarter-to-quarter increase. Propylene fractionation volumes were 73 MBPD during the first quarter of 2011 compared to 80 MBPD during the first quarter of 2010. The quarter-to-quarter increase in gross operating margin is primarily due to lower operating expenses, which more than offset the effects of lower propylene fractionation and pipeline transportation volumes during the first quarter of 2011 compared to the first quarter of 2010.

Gross operating margin from butane isomerization was $25.7 million for the first quarter of 2011 compared to $14.8 million for the first quarter of 2010, a $10.9 million quarter-to-quarter increase. Butane isomerization volumes increased to 88 MBPD during the first quarter of 2011 from 73 MBPD during the first quarter of 2010. The quarter-to-quarter increase in gross operating margin is primarily due to higher isomerization volumes and commodity prices, which resulted in increased revenues from by-product sales.

Gross operating margin from octane enhancement was $6.1 million for the first quarter of 2011 compared to $4.1 million for the first quarter of 2010. The $2.0 million quarter-to-quarter increase in gross operating margin is primarily due to higher sales volumes and lower utilities, maintenance and other operating expenses during the first quarter of 2011 compared to the first quarter of 2010. Octane enhancement production volumes were 12 MBPD during the first quarter of 2011 compared to 11 MBPD during the first quarter of 2010.

Gross operating margin from refined products pipelines and related activities was $18.3 million for the first quarter of 2011 compared to $48.9 million for the first quarter of 2010, a $30.6 million quarter-to-quarter decrease. Pipeline transportation volumes for the refined products business decreased to 642 MBPD during the first quarter of 2011 from 682 MBPD during the first quarter of 2010. Gross operating margin from our Products Pipeline System decreased $28.3 million quarter-to-quarter primarily due to lower transportation volumes and higher operating expenses during the first quarter of 2011 compared to the first quarter of 2010. Equity earnings from our investment in Centennial decreased $2.3 million quarter-to-quarter primarily due to lower transportation volumes. Net to our interest, transportation volumes on the Centennial pipeline decreased 10 MBPD quarter-to-quarter.

Gross operating margin from the Products Pipeline System decreased an estimated $13.5 million quarter-to-quarter due to lower revenues and higher operating expenses attributable to the continuing impact of a pipeline leak that occurred in New York state in the third quarter of 2010. Following our repair of the leak, the affected segment of pipe was tested and returned to service in February 2011. Gross operating margin also decreased $9.7 million quarter-to-quarter primarily due to lower transportation volumes on our Products Pipeline System originating from the Gulf Coast region for delivery to Midwest markets. The remaining $5.1 million quarter-to-quarter decrease in gross operating margin from our Products Pipeline System is primarily due to higher operating costs such as expenses for maintenance and pipeline integrity work.

Gross operating margin from marine transportation and other segment services was $13.5 million for the first quarter of 2011 compared to $9.1 million for the first quarter of 2010. Segment gross operating margin for the first quarter of 2011 includes $1.9 million from trucking operations, which we acquired from EPCO in September 2010. The remaining $2.5 million quarter-to-quarter increase in gross operating margin is primarily due to lower repair and maintenance expenses associated with our fleet of marine vessels during the first quarter of 2011 compared to the first quarter of 2010.

Other Investments. Gross operating margin from this business segment was $6.3 million for the first quarter of 2011 compared to $10.6 million for the first quarter of 2010, a $4.3 million quarter-to-quarter decrease. This segment reflects our noncontrolling ownership interest in Energy Transfer Equity, which we account for using the equity method.

According to financial statements filed with the SEC, Energy Transfer Equity reported operating income of $364.2 million for the first quarter of 2011 compared to $338.9 million for the first quarter of 2010, a $25.3 million quarter-to-quarter increase. Operating income from Energy Transfer Equity's investment in ETP increased $18.8 million quarter-to-quarter primarily due to earnings generated from newly constructed assets, principally ETP's Tiger pipeline that was placed into service in December 2010. Operating income from Energy Transfer Equity's investment in RGNC was $8.1 million for the first quarter of 2011. Energy Transfer Equity acquired interests in and began consolidating RGNC in May

2010. Also included in operating income are Energy Transfer Equity's standalone and other expenses, which increased $1.6 million quarter-to-quarter.

Collectively, all other items included in Energy Transfer Equity's net income decreased $30.3 million quarter-to-quarter primarily due to higher interest expense in the first quarter of 2011 compared to the first quarter of 2010. Energy Transfer Equity's interest expense on a standalone basis (i.e., the parent company and not on a consolidated basis) increased $24.2 million quarter-to-quarter primarily due to its issuance in September 2010 of $1.8 billion in principal amount of 10-year senior notes.

After taking into account noncontrolling interests, income attributable to the partners of Energy Transfer Equity decreased to $88.6 million for the first quarter of 2011 from $112.8 million for the first quarter of 2010. Before the amortization of our excess cost amounts related to this investment, equity income from our investment in Energy Transfer Equity was a collective $15.4 million for the first quarter of 2011 versus $19.8 million for the first quarter of 2010. Our equity income from this investment was reduced by $9.1 million of excess cost amortization during each of the first quarters of 2011 and 2010. For additional information regarding our investment in Energy Transfer Equity, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Liquidity and Capital Resources

At March 31, 2011, we had $150.4 million of unrestricted cash on hand and $2.38 billion of available borrowing capacity under our consolidated revolving credit facilities, including $634.5 million of available borrowing capacity under Duncan Energy Partners' revolving credit facility. Our primary cash requirements are for routine operating expenses, debt service, working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term cash requirements for operating expenses and sustaining capital expenditures using operating cash flows and borrowings under revolving credit arrangements. Our expenditures for long-term productive assets (e.g., business expansion projects and acquisitions) are expected to be funded by a variety of sources (either separately or in combination) including the use of operating cash flows, borrowings under credit facilities, and proceeds from the issuance of additional equity and debt securities and divestitures. 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 expected recurring operating and investing activities.

We had approximately $14.04 billion of principal amounts outstanding under consolidated debt agreements at March 31, 2011. In January 2011, EPO issued an aggregate of $1.5 billion in principal amount of senior unsecured notes. EPO issued $750.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes AA") at 99.901% of their principal amount and $750.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes BB") at 99.317% of their principal amount. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay $450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.   In January 2011, EPO utilized the 2010 Shelf to issue its Senior Notes AA and BB (see above).

Enterprise also has registration statements on file with the SEC in connection with its distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP"). After taking into account limited partner units issued under these registration statements through March 31, 2011, Enterprise may issue an additional 27,940,166 common units under its DRIP and 53,940 common units under its EUPP. The following table reflects the number of common units issued and the net cash proceeds received from Enterprise's DRIP and EUPP during the three months ended March 31, 2011:

	Number of Common Units Issued	Net Cash Proceeds
February DRIP and EUPP	506,908	$ 21.0

Net cash proceeds received in 2011 from Enterprise's DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Credit Ratings

At May 10, 2011, the investment-grade credit ratings of EPO's senior unsecured debt securities were: Baa3 from Moody's Investor Services ("Moody's"); BBB- from Fitch Ratings; and BBB- from Standard and Poor's. In March 2011, Moody's reaffirmed its corporate credit rating of EPO and revised its outlook for EPO's business from "stable" to "positive." 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 other rating agencies.

A downgrade of EPO's credit ratings could result in us posting financial collateral in connection with our guaranty of Centennial's debt, which was $54.3 million at March 31, 2011. Furthermore, 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 downgraded below investment grade.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented (dollars in millions). For information regarding the individual components of our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report.

	For the Three Months Ended March 31,	
	2011	2010
Net cash flows provided by operating activities	$ 802.7	$ 696.4
Cash used in investing activities	726.4	370.5
Cash provided by (used in) financing activities	8.6	(246.4)

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstocks 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 2010 Form 10-K.

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

Comparison of Three Months Ended March 31, 2011 with Three Months Ended March 31, 2010

Operating Activities. The $106.3 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding cash distributions received from unconsolidated affiliates and cash payments for interest) increased $152.5 million quarter-to-quarter. The increase in operating cash flow is generally due to increased profitability and the timing of related cash receipts and disbursements.

§ Cash payments for interest increased $37.3 million quarter-to-quarter primarily due to an increase in debt obligations quarter-to-quarter. Our average debt outstanding was $14.11 billion during the three months ended March 31, 2011 compared to $12.26 billion during the three months ended March 31, 2010.

Investing Activities. The $355.9 million increase in cash used for investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $366.1 million quarter-to-quarter primarily due to our Eagle Ford Shale and Haynesville Shale natural gas pipeline projects, which began ramping up construction in mid-2010. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 2.

§ Cash outflows related to restricted cash increased $54.8 million quarter-to-quarter primarily due to increases in the margin requirements of our commodity hedging positions.

§ Proceeds from asset sales and related transactions increased $62.5 million quarter-to-quarter, primarily from sales of certain marine assets and a non-strategic fractionation facility during the first quarter of 2011.

Financing Activities. Cash provided by financing activities was $8.6 million for the three months ended March 31, 2011 compared to cash used in financing activities of $246.4 million for the three months ended March 31, 2010.

As discussed under "Basis of Financial Statement Presentation" within this Item 2, the financial statements of Enterprise prior to the Holdings Merger were those of Holdings. As a result, cash distributions to partners for the first quarter of 2010 represent payments to the former unitholders of Holdings whereas cash distributions to partners for the first quarter of 2011 represent payments to the unitholders of Enterprise. Also, cash distributions to noncontrolling interests for the first quarter of 2010 include cash payments to the unitholders of Enterprise (other than Holdings). Cash contributions from noncontrolling interests for the first quarter of 2010 primarily represent proceeds from Enterprise equity offerings (other than purchases by Holdings).

In general, the $255.0 million quarter-to-quarter change in cash flows from financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements of $505.6 million for the first quarter of 2011 compared to net repayments under our consolidated debt agreements of $237.7 million for the first quarter of 2010. During the first quarter of 2011, EPO issued $1.5 billion in senior notes (Senior Notes AA and BB) and repaid its $450 million Senior Notes B.

- § Cash distributions to partners and noncontrolling interests were a combined $496.9 million for the first quarter of 2011 compared to $425.7 million for the first quarter of 2010. The increase in cash distributions is primarily due to an increase in the number of distribution-bearing common units outstanding and the quarterly distribution rates of Enterprise.

- § Cash contributions from noncontrolling interests were $1.3 million for the first quarter of 2011 compared to $417.3 million for the first quarter of 2010. The issuance of common units by Enterprise (other than to Holdings) during the first quarter of 2010 generated $417.1 million of net cash proceeds. Net cash proceeds from the issuance of Enterprise common units during the first quarter of 2011 were $21.0 million.

Capital Spending

An integral part of our business strategy involves expansion through growth capital projects, business combinations 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 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 for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2011	2010
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 710.3	$ 344.2
Capital spending for business combinations	--	2.2
Capital spending for intangible assets	3.6	--
Capital spending for investments in unconsolidated affiliates	3.8	7.7
Total capital spending	$ 717.7	$ 354.1

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2011 will be approximately $3.0 billion, which includes estimated expenditures of $2.8 billion for growth capital projects and $200 million for sustaining capital expenditures.

The preceding forecast of consolidated capital expenditures is based on our announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, issuance of equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs associated with unforeseen acquisition opportunities.

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

At March 31, 2011, we had approximately $1.64 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects involving natural gas pipeline projects in the Eagle Ford Shale and Haynesville Shale.

Pipeline Integrity Costs

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

The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2011	2010
Expensed	$ 7.7	$ 9.4
Capitalized	10.7	2.7
Total	$ 18.4	$ 12.1

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $84.6 million for the remainder of 2011. The cost of our pipeline integrity program was $79.8 million for the year ended December 31, 2010.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2010 Form 10-K. The following estimates, in our opinion, are subjective in nature, require the exercise of professional 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 the use of estimates when recording revenue and expense accruals;
§ reserves for environmental matters and litigation contingencies; and
§ natural gas imbalances.

When used in the preparation of our consolidated financial statements, such estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised 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 consolidated financial position, results of operations and cash flows.

Other Items

Contractual Obligations

With the exception of (i) routine fluctuations in the balance of our consolidated revolving credit facilities, (ii) the issuance of Senior Notes AA and BB in January 2011 and (iii) the repayment of Senior Notes B in February 2011, there have been no significant changes in our consolidated debt obligations since those reported in our 2010 Form 10-K. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. For additional information regarding insurance matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

See "Significant Recent Developments" for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. We will seek reimbursement of the costs associated with this incident from our insurance carriers.

Non-GAAP Reconciliations

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2011	2010
Total segment gross operating margin	$ 875.4	$ 806.0
Adjustments to reconcile total segment gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(230.8)	(212.4)
Non-cash asset impairment charges	--	(1.5)
Operating lease expenses paid by EPCO	(0.2)	(0.2)
Gains from asset sales and related transactions in operating costs and expenses	18.4	7.3
General and administrative costs	(37.9)	(40.3)
Operating income	624.9	558.9
Other expense, net	(183.3)	(157.8)
Income before provision for income taxes	$ 441.6	$ 401.1

Off-Balance Sheet Arrangements

In March 2011, Evangeline made the final scheduled payment of $3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

In April 2011, we refinanced the Poseidon revolving credit facility. The new replacement facility matures in April 2015 and has a borrowing capacity of $125 million. At March 31, 2011, the principal amount outstanding under the previous Poseidon revolving credit agreement totaled $92.0 million.

Except for the matters noted above, there have been no other significant changes in our off-balance sheet arrangements since those reported in our 2010 Form 10-K.

Regulatory Matters

For information regarding regulatory matters, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Related Party Transactions

On April 28, 2011, we, our general partner and two of our subsidiaries entered into a definitive merger agreement with Duncan Energy Partners and DEP GP. See "Significant Recent Developments" within this Item 2 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise. For additional information regarding our related party transactions, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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 and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. Derivative instruments typically 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 2010 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 interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our interest rate swaps outstanding at March 31, 2011:

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 2.3%	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
Senior Notes AA	10 fixed-to-floating swaps	$750.0	1/11 to 2/16	3.2% to 1.3%	Fair value hedge
Non-Hedged Swaps	2 floating-to-fixed swaps	$250.0	9/07 to 8/11	0.3% to 4.8%	Mark-to-market
Non-Hedged Swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.3% to 2.0%	Mark-to-market

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 March 31, 2011	Swap Fair Value at April 19, 2011
FV assuming no change in underlying interest rates	*Asset*	$ 33.5	$ 40.0
FV assuming 10% increase in underlying interest rates	*Asset*	26.3	33.5
FV assuming 10% decrease in underlying interest rates	*Asset*	40.8	46.7

The following table summarizes our forward starting interest rate swaps outstanding at March 31, 2011, 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	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

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

Scenario	Resulting Classification	Swap Fair Value at March 31, 2011	Swap Fair Value at April 19, 2011
FV assuming no change in underlying commodity prices	*Asset*	$ 39.1	$ 19.3
FV assuming 10% increase in underlying commodity prices	*Asset*	93.8	73.0
FV assuming 10% decrease in underlying commodity prices	*Liability*	(18.1)	(36.7)

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 such price risks, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts.

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 natural 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 December 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.

At March 31, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of $487.7 million on 11.4 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2011. At April 29, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of $527.7 million on 13.3 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2011.

§ 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.

Certain basis swaps, basis spread options and other financial derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

The following table summarizes our commodity derivative instruments outstanding at March 31, 2011:

Derivative Purpose	Volume (1) Current	Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Enterprise:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	33.4 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	7.0 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (4)	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	3.0 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	4.1 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	4.3 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	3.6 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	4.0 MMBbls	0.1 MMBbls	Cash flow hedge
Forecasted sales of refined products	4.0 MMBbls	0.1 MMBbls	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	3.6 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	5.2 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise:			
Natural gas risk management activities (5,6)	355.5 Bcf	55.6 Bcf	Mark-to-market
Refined products risk management activities (6)	4.5 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	7.3 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	2.4 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 2013.
(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) Forecasted sales of NGL volumes under Natural gas processing exclude 3.0 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(5) Current and long-term volumes include approximately 151.9 Bcf and 4.1 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.

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 March 31, 2011	Portfolio Fair Value at April 19, 2011
FV assuming no change in underlying commodity prices	*Liability*	$ (15.7)	$ (9.8)
FV assuming 10% increase in underlying commodity prices	*Liability*	(22.2)	(12.3)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(9.1)	(7.3)

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 March 31, 2011	Portfolio Fair Value at April 19, 2011
FV assuming no change in underlying commodity prices	*Liability*	$ (114.1)	$ (147.4)
FV assuming 10% increase in underlying commodity prices	*Liability*	(185.0)	(218.9)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(43.2)	(75.9)

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 March 31, 2011	Portfolio Fair Value at April 19, 2011
FV assuming no change in underlying commodity prices	*Liability*	$ (5.1)	$ (6.2)
FV assuming 10% increase in underlying commodity prices	*Liability*	(13.7)	(16.0)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(3.5)	3.7

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 quarterly 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 first quarter of 2011, 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 14, “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 2010 annual report on Form 10-K, in addition to other information in such annual report. 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.

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

As of March 31, 2011, 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 three months ended March 31, 2011.

The following table summarizes our repurchase activity during 2011 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 2011 (1)	91,126	$ 43.00	--	--

(1) Of the 336,227 restricted common units that vested in February 2011 and converted to common units, 91,126 units were sold back to us by employees to cover related withholding tax requirements.

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	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).
2.2	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).
2.3	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).
2.4	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).
2.5	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).
2.6	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).
2.7	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).
2.8	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).
2.9	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).
2.10	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).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
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	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).

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3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Certificate of Formation of EPE Holdings, LLC (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.5	Certificate of Amendment to Certificate of Formation of EPE Holdings, LLC, filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.6	Fourth Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC dated effective as of November 22, 2010 (incorporated by reference to Exhibit 3.3 to Form 8-K filed November 23, 2010).
3.7	First Amendment to Fourth Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated effective as of November 23, 2010 (changing name to Enterprise Products Holdings LLC) (incorporated by reference to Exhibit 3.4 to Form 8-K filed November 23, 2010).
3.8	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).
3.9	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).
3.10	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-1/A 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).
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 8-K filed May 20, 2010).
4.26	Twentieth Supplemental Indenture, dated as of January 13, 2011, 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 January 13, 2011).
4.27	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.28	Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.29	Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.30	Global Note representing $500.0 million principal amount of 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 $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).
4.34	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).
4.35	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).
4.36	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).

4.42	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).
4.43	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).
4.44	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).
4.45	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).
4.46	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).
4.47	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).
4.48	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).
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.54	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).

4.60	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.61	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).
4.62	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).
4.63	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).
4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	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).
4.69	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).
4.70	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).

4.71	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).
4.72	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.73	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).
4.74	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	First Amendment to Second Amended and Restated Limited Liability Company Agreement of Acadian Gas dated effective March 15, 2011 (incorporated by reference to Exhibit 10.1 to Form 8-K filed March 15, 2011).
10.2	Voting Agreement, dated as of April 28, 2011, by and among Duncan Energy Partners L.P. Enterprise Products Partners L.P. and Enterprise GTM Holdings L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 29, 2011).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the March 31, 2011 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 March 31, 2011 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the March 31, 2011 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the March 31, 2011 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

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.

\# 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 May 10, 2011.

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

By:	Enterprise Products Holdings LLC, as General Partner
By:	/s/ Michael J. Knesek
Name:	Michael J. Knesek
Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner

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: May 10, 2011

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products Holdings 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: May 10, 2011

/s/ W. Randall Fowler

Name: W. Randall Fowler

Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

**CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER
OF ENTERPRISE PRODUCTS HOLDINGS 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 three months ended March 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Michael A. Creel

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

Date: May 10, 2011

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS HOLDINGS 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 three months ended March 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ W. Randall Fowler

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

Date: May 10, 2011