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

FORM 8-K

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

Date of report (Date of earliest event reported): March 31, 2004

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in its Charter)

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

2727 North Loop West, Houston, Texas	**77008-1044**
(Address of Principal Executive Offices)	(Zip Code)

(713) 880-6500
(Registrant's Telephone Number, including Area Code)

Item 5. OTHER EVENTS.

We are filing the unaudited consolidated balance sheet of Enterprise Products GP, LLC as of March 31, 2004, which is included as Exhibit 99.1 to this current report. Enterprise Products GP, LLC is the general partner of Enterprise Products Partners L.P.

Item 7. FINANCIAL STATEMENTS AND EXHIBITS.

(c) Exhibits.

99.1 Unaudited Consolidated Balance Sheet of Enterprise Products GP, LLC as of March 31, 2004.

SIGNATURES

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

ENTERPRISE PRODUCTS PARTNERS L.P.

By: Enterprise Products GP, LLC, as general partner

Date: July 29, 2004

By: /s/ Michael J. Knesek

Michael J. Knesek
Vice President, Controller, and
Principal Accounting Officer of
Enterprise Products GP, LLC

EXHIBIT 99.1

Enterprise Products GP, LLC

Consolidated Balance Sheet as of March 31, 2004

ENTERPRISE PRODUCTS GP, LLC

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ENTERPRISE PRODUCTS GP, LLC
UNAUDITED CONSOLIDATED BALANCE SHEET
AT MARCH 31, 2004
(Dollars in thousands)

	March 31, 2004
ASSETS	
Current Assets	
Cash and cash equivalents (includes restricted cash of $8,026)	$ 53,138
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,438	398,831
Accounts receivable - affiliates	9,751
Inventories	168,330
Prepaid and other current assets	55,973
Total current assets	686,023
Property, Plant and Equipment, net	2,951,621
Investments in and Advances to Unconsolidated Affiliates	766,293
Intangible Assets, net of accumulated amortization of $44,193	265,071
Goodwill	82,427
Deferred Tax Asset	8,784
Long-term Receivables	5,282
Other Assets	17,133
Total	$ 4,782,634
LIABILITIES AND MEMBERS' EQUITY	
Current Liabilities	
Current maturities of debt	$ 15,000
Accounts payable - trade	58,507
Accounts payable - affiliates	27,126
Accrued gas payables	588,340
Accrued expenses	15,633
Accrued interest	14,702
Other current liabilities	51,164
Total current liabilities	770,472
Long-Term Debt	2,195,876
Other Long-Term Liabilities	9,260
Commitments and Contingencies	
Minority Interest	1,753,368
Members' Equity	53,658
Total	$ 4,782,634

See notes to unaudited consolidated balance sheet.

1. ORGANIZATION AND CONSOLIDATION

ENTERPRISE PRODUCTS GP, LLC ("EPGP") is a privately-held Delaware limited liability company formed in May 1998 to become the general partner of Enterprise Products Partners L.P. ("EPD") and its wholly owned operating subsidiary, Enterprise Products Operating L.P. (the "Operating Partnership"). Our primary business purpose is to manage the affairs and operations of EPD and its subsidiaries. EPD, including its consolidated subsidiaries, is a publicly traded Delaware limited partnership listed on the New York Stock Exchange ("NYSE") under symbol "EPD." EPD conducts substantially all of its business through the Operating Partnership. EPD and the Operating Partnership were formed to acquire, own and operate the natural gas liquids ("NGL") business of EPCO, Inc. ("EPCO", formerly Enterprise Products Company).

Unless the context requires otherwise, references to "we", "us", "our" or the "Company" within these notes shall mean EPGP and its consolidated subsidiaries, which include EPD and its subsidiaries. References to "Shell" shall mean Shell Oil Company, its subsidiaries and affiliates. References to "El Paso" shall mean El Paso Corporation and its affiliates.

At March 31, 2004, Duncan Family Interests, Inc. ("DFI", formerly EPC Partners II, Inc.) owned 95%, and Dan Duncan, LLC owned 5% of the membership interests of EPGP. DFI and Dan Duncan, LLC are hereafter collectively referred to as the "Members." EPCO is the ultimate parent of DFI and an affiliate of Dan Duncan, LLC.

As a result of DFI acquiring Shell's 30% member interest in EPGP on September 12, 2003, the financial statements of EPD were consolidated with those of EPGP beginning in September 2003. This accounting consolidation is required because Shell's minority interest rights in EPGP (which gave them significant participating rights) were terminated as a result of the purchase. This fact, along with DFI's indirect control of EPD through its majority common unit holdings, gives EPGP the ability to exercise control over EPD. All intercompany accounts and transactions have been eliminated in consolidation.

EPD and its subsidiaries conduct substantially all of our business. We have no independent operations and no material assets outside those of EPD. The number of reconciling items between our consolidated balance sheet and that of EPD are few. The most significant is that relating to minority interest in our net assets by the limited partners of EPD and the elimination of our investment in EPD with our underlying partner's capital account in EPD. See Note 9 for additional details of minority interest in our consolidated subsidiaries.

In the opinion of the Company, the accompanying unaudited consolidated balance sheet includes all adjustments consisting of normal recurring accruals necessary for a fair presentation. Although we believe the disclosures are adequate to make the information presented in the unaudited balance sheet not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. EPGP's unaudited March 31, 2004 balance sheet should be read in conjunction with its audited December 31, 2003 balance sheet filed on Form 8-K on March 22, 2004. In addition, this financial information should be read in conjunction with EPD's Form 10-K (Commission File No. 1-14323) for the year ended December 31, 2003 and its Form 10-Q for the three months ended March 31, 2004. Certain abbreviated entity names and other capitalized and industry terms used within these footnotes are defined in the glossary of EPD's Form 10-Q for the three months ended March 31, 2004.

Dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars, unless otherwise indicated.

The following tables show the consolidation of EPD's consolidated balance sheet at March 31, 2004 with that of our own (dollars in thousands):

	Consolidated EPD and subsidiaries	EPGP	Adjustments and Eliminations	Consolidated EPGP and subsidiaries
ASSETS				
Current Assets				
Cash and cash equivalents (includes restricted cash of $8,026 at March 31, 2004)	$ 52,821	$ 317		$ 53,138
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,438 at March 31, 2004	398,831			398,831
Accounts receivable - affiliates	9,751	(1,917)	$ 1,917	9,751
Inventories	168,330			168,330
Prepaid and other current assets	55,973			55,973
Total current assets	685,706	(1,600)	1,917	686,023
Property, Plant and Equipment, net	2,951,621			2,951,621
Investments in and Advances to Unconsolidated Affiliates	766,293	34,209	(34,209)	766,293
Intangible Assets, net of accumulated amortization of $44,193 at March 31, 2004	265,071			265,071
Goodwill	82,427			82,427
Deferred Tax Asset	8,784			8,784
Long-term receivables	5,282			5,282
Other Assets	17,133			17,133
Total	$ 4,782,317	$ 32,609	$ (32,292)	$ 4,782,634

	Consolidated EPD and subsidiaries	EPGP	Adjustments and Eliminations	Consolidated EPGP and subsidiaries
LIABILITIES AND MEMBERS' EQUITY				
Current Liabilities				
Current maturities of debt	$ 15,000			$ 15,000
Accounts payable - trade	58,507			58,507
Accounts payable - affiliates	25,209		$ 1,917	27,126
Accrued gas payables	588,340			588,340
Accrued expenses	15,633			15,633
Accrued interest	14,702			14,702
Other current liabilities (1)	50,585	$ 579		51,164
Total current liabilities	767,976	579	1,917	770,472
Long-Term Debt	2,195,876			2,195,876
Other Long-Term Liabilities (1)	9,027	233		9,260
Commitments and Contingencies				
Minority Interest	88,531		1,664,837	1,753,368
Members' Equity				
Partnership Equity				
Limited Partners	1,676,253		(1,676,253)	
General Partner	34,209		(34,209)	
Treasury units	(11,416)		11,416	
Accumulated Other Comprehensive Income	21,861			21,861
	1,720,907		(1,699,046)	21,861
Members' Equity		31,797		31,797
Total Members' Equity				53,658
Total	$ 4,782,317	$ 32,609	$ (32,292)	$ 4,782,634

(1) A change in accounting principle occurred on January 1, 2004 to change the method our majority owned BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. These major maintenance costs, which typically result in facility shutdowns for 30 to 45 days, are principally comprised of amounts paid to third parties for materials, contract services, and other related items. We have historically used the expense-as-incurred method for planned major maintenance activities. The change in accounting for our majority owned BEF subsidiary conforms the Company's accounting for all planned major maintenance costs and changes the method to better reflect expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances.

2. OTHER RECENTLY ISSUED ACCOUNTING STANDARDS AND GUIDANCE

FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated balance sheet.

Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-16, "Accounting for Investments in Limited Liability Companies." This accounting guidance requires that investments in limited liability companies (or "LLCs") that have separate ownership accounts for each investor be accounted for similar to a limited partnership investment under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors would be required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Currently, we account for our 13.1% investment in Venice Energy Services Company, LLC ("VESCO") using the cost method. As a result, we have recognized dividend income from VESCO to the extent that we have received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we will record a retroactive cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in prior periods and (ii) the dividend income from VESCO that was recorded using the cost method. We are currently studying the effect that EITF 03-16 will have on our investment in VESCO; however, based on information available, we do not believe that the implementation of this new accounting guidance will have a material effect on the balance sheet of EPGP.

3. BUSINESS COMBINATIONS

We did not enter into any business acquisitions during the first quarter of 2004; however, we are still expecting completion of the proposed merger with GulfTerra during the second half of 2004. In general, the proposed merger with GulfTerra involves the following three steps:

- *Step One*. On December 15, 2003, we purchased a 50% membership interest in GulfTerra's general partner ("GulfTerra GP") for $425 million. GulfTerra's general partner owns a 1% general partner interest in GulfTerra. This investment is accounted for using the equity method and is already recorded in our historical balance sheet at December 31, 2003. See Note 6 regarding preliminary estimates of the purchase price allocation for GulfTerra GP. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which are referred to as Step Two and Step Three, do not occur.

- *Step Two*. If all necessary regulatory approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method, and GulfTerra will be a consolidated subsidiary of Enterprise. Step Two of the proposed merger includes the following transactions:

  - El Paso's exchange of its remaining 50% membership interest in GulfTerra GP for a cash payment from us of $370 million (which will not be funded or reimbursed by EPD) and a 9.9% membership in us, and the subsequent capital contribution by us of such 50% membership interest in GulfTerra GP to EPD (without increasing our general partner interest in EPD's earnings or cash distributions nor will we receive common units or other consideration for this transfer).

  - Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million.

  - The exchange of each remaining GulfTerra common unit for 1.81 EPD common units, resulting in the issuance of approximately 105.1 million of EPD's common units to GulfTerra unitholders.

- *Step Three*. Immediately after Step Two is completed, we expect to acquire certain South Texas midstream energy assets from El Paso for $150 million plus the value of then existing inventories related to such assets.

We anticipate that a portion of the purchase price of Steps Two and Three of the merger will be financed with the net proceeds from equity offerings. We expect to finance the remaining portion of this purchase price through one or more issuances of debt securities, a temporary acquisition term facility, borrowings under our credit facilities, or through any combination of the foregoing.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or issue is approximately $4.0 billion. For a period of three years following the closing of the proposed merger, at our request El Paso will provide certain support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs for such services (excluding any overhead costs). El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both Enterprise and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions of the proposed merger will be satisfied, we expect to complete the transaction in the second half of 2004.

To review a copy of the merger agreement and related transaction documents, please read the Current Reports on Form 8-K filed by EPD with the SEC on December 15, 2003 and April 21, 2004.

4. INVENTORIES

Our inventories were as follows at March 31, 2004:

Working inventory	$ 164,072
Forward-sales inventory	4,258
Inventory	$ 168,330

Our regular trade (or “working”) inventory is comprised of inventories of natural gas, NGLs and petrochemical products that are available for sale or used in the provision of services. The forward sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts. Both inventories are valued at the lower of average cost or market.

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation were as follows at March 31, 2004:

	Estimated Useful Life in Years	
Plants and pipelines [1]	5-35 [4]	$ 3,258,067
Underground and other storage facilities [2]	5-35 [5]	292,263
Transportation equipment [3]	3-10	6,231
Land		23,447
Construction in progress		40,835
Total		3,620,843
Less accumulated depreciation		669,222
Property, plant and equipment, net		$ 2,951,621

(1) Plants and pipelines includes processing plants; NGL, petrochemical and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities includes underground product storage caverns; storage tanks; water wells; and related assets.
(3) Transportation equipment includes vehicles and similar assets used in our operations.
(4) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years, pipelines, 30-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.
(5) In general, the estimated useful lives of major components of this category are: underground storage wells, 30-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

6. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for using the equity or cost methods. The investments in and advances to these unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of business segments, see Note 11. The following table shows our investments in and advances to unconsolidated affiliates:

	Ownership Percentage at March 31, 2004	March 31, 2004
Accounted for using the equity method:		
Pipeline:		
GulfTerra GP	50.0%	$ 425,082
Neptune	25.7%	73,539
Tri-States	50.0%	43,401
Starfish	50.0%	40,287
Dixie	19.9%	36,066
Nemo	33.9%	12,691
Belle Rose	41.7%	10,511
Evangeline	49.5%	2,675
Fractionation:		
Promix	33.3%	39,772
BRF	32.3%	27,459
BRPC	30.0%	16,657
La Porte	50.0%	5,153
Accounted for using the cost method:		
Processing:		
VESCO	13.1%	33,000
Total		$ 766,293

Our initial investment in Promix, La Porte, Dixie, Tri-States, Neptune, Nemo and GulfTerra GP exceeded our share of the historical cost of the underlying net assets of such entities (“excess cost”). The excess cost amounts are reflected in our investments in and advances to unconsolidated affiliates for these entities. That portion of excess cost attributable to tangible or amortizable intangible assets of each entity is amortized over the estimated useful of the underlying asset(s) as a reduction in equity earnings from the investee. That portion of excess cost attributable to goodwill or non-amortizable intangible assets is not amortized. Equity method investments, including their associated excess cost amounts, are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. The following table summarizes our excess cost information at March 31, 2004 by the business segment to which the unconsolidated affiliates relate:

		Initial Excess Cost attributable to		Unamortized balance at
	Amort. Periods	Tangible assets	Goodwill (1)	March 31, 2004
Fractionation	20-35 years	$ 8,828		$ 6,676
Pipelines (2)	35 years	45,698	$ 337,460	378,085

(1) Excess cost attributable to goodwill is not amortized; however, our investments in unconsolidated affiliates (which include excess cost amounts) are tested for impairment whenever events or circumstances indicate that there is a loss in value of the investment which is an other than temporary decline.

(2) This category includes our preliminary allocation of GulfTerra GP's $328.2 million of excess cost to goodwill.

The Pipelines section in the preceding table includes $337.5 million of excess cost attributable to goodwill, of which $328.2 million results from our December 2003 purchase of a 50% membership interest in GulfTerra GP. The allocation of the $328.2 million of excess cost to goodwill (which represents potential intangible assets, excess of fair values over carrying values of tangible assets and remaining goodwill, if any) is preliminary pending completion of a fair value analysis which is expected to be completed during the last half of 2004. The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts included in this excess cost were ultimately assigned to tangible or amortizable intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation over an estimated useful life of 20-years to various fair values.

Amount allocated to Tangible or Amortizable Assets out of GulfTerra GP Excess Cost Goodwill	**Excess Cost attributed to tangible or intangible assets**	**Estimated Annual Reduction in Equity Earnings from GulfTerra GP**
20% of excess cost or $65.6 million	$ 65,643	$ 3,282
40% of excess cost or $131.3 million	131,286	6,564
60% of excess cost or $196.9 million	196,928	9,846
80% of excess cost or $262.6 million	262,571	13,129
100% of excess cost or $328.2 million	328,214	16,411

Expected change in accounting method for VESCO

As a result of newly issued accounting guidance per EITF 03-16, we expect to change our method of accounting for VESCO from the cost method to the equity method on July 1, 2004. The VESCO investment consists of a 13.1% membership interest in a limited liability company that owns a natural gas processing plant, NGL fractionation facilities, storage assets and gas gathering pipelines located in south Louisiana.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

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

	At March 31, 2004		
	Gross Value	Accum. Amort.	Carrying Value
Shell natural gas processing agreement	$ 206,216	$ (36,824)	$ 169,392
Mont Belvieu Storage II contracts	8,127	(523)	7,604
Mont Belvieu Splitter III contracts	53,000	(3,281)	49,719
Toca-Western natural gas processing contracts	11,187	(1,025)	10,162
Toca-Western NGL fractionation contracts	20,042	(1,838)	18,204
Venice contracts	6,635	(251)	6,384
Port Neches pipeline contracts	2,400	(403)	1,997
BEF UOP License Fee	1,657	(48)	1,609
Total	$ 309,264	$ (44,193)	$ 265,071

All of the intangible assets noted in the preceding table are subject to amortization. Amortization expense for the three months ended March 31, 2004 was $3.8 million. For the remainder of 2004, amortization expense attributable to these intangible assets is currently estimated at $11.5 million.

Goodwill

The following table summarizes our goodwill amounts at March 31, 2004 (excluding amounts included in the carrying value of unconsolidated affiliates – See Note 6).

	Segment Affiliation	Goodwill Balance
Splitter III acquisition (1)	Fractionation	$ 73,690
MBA acquisition (2)	Fractionation	7,857
Wilprise acquisition (3)	Pipelines	880
		$ 82,427

(1) Amount recorded in connection with our acquisition of propylene fractionation assets from Diamond-Koch in February 2002.
(2) Amount recorded in connection with our acquisition of an additional interest in Mont Belvieu Associates in July 2001, which owned an interest in our Mont Belvieu NGL fractionation facility.
(3) Amount recorded in connection with our acquisition of an additional 37.4% in Wilprise in October 2003.

8. DEBT OBLIGATIONS

Our debt consisted of the following :

		March 31, 2004
Borrowings under:		
Interim Term Loan, variable rate, repaid in May 2004 (1)	$	225,000
364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity		90,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2)		160,000
Senior Notes A, 8.25% fixed rate, due March 2005		350,000
Seminole Notes, 6.67% fixed rate, $15 million due in December 2004 and 2005 (3)		30,000
MBFC Loan, 8.70% fixed rate, due March 2010		54,000
Senior Notes B, 7.50% fixed rate, due February 2011		450,000
Senior Notes C, 6.375% fixed rate, due February 2013		350,000
Senior Notes D, 6.875% fixed rate, due March 2033		500,000
Total principal amount		2,209,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt (see Note 12)		7,828
Less unamortized discount on Senior Notes A, B, and D		(5,952)
Subtotal long-term debt		2,210,876
Less current maturities of debt (4)		(15,000)
Long-term debt (4)	$	2,195,876
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility	$	1,300

(1) We used the proceeds from EPD's May 2004 common unit offering to fully repay the Interim Term Loan.

(2) This revolving credit facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.

(3) Solely as to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at March 31, 2004 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.

(4) In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced," long-term and current maturities of debt at March 31, 2004 reflect the classification of such debt obligations at May 5, 2004. With respect to our 364-Day Revolving Credit Facility, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement. With respect to our Interim Term Loan, we reclassified this amount to long-term debt at March 31, 2004 since we used the proceeds from EPD's May 2004 equity offering to repay this obligation.

Scheduled future maturities of long-term debt. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. Scheduled future maturities of debt at March 31, 2004 were: $240 million due in 2004; $615 million due in 2005; $54 million due in 2010; $450 million due in 2011; $350 million due in 2013; and $500 million due in 2033. We used $353.1 million in net proceeds from EPD's May 2004 equity offering to repay the $225 million Interim Term Loan and approximately $130 million to temporarily reduce debt outstanding under our revolving credit facilities.

Parent-Subsidiary guarantor relationships. Through guarantor agreements which are nonrecourse to us, EPD acts as guarantor of the debt obligations of the Operating Partnership, with the exception of the Seminole

Notes. If the Operating Partnership were to default on any debt EPD guarantees, EPD would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we owned an effective 88.4% of its capital stock at July 29, 2004).

Covenants. We were in compliance with the various covenants of our debt agreements at March 31, 2004.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable rate debt obligations for the three months ended March 31, 2004:

	Range of interest rates paid	Weighted-average interest rate paid
364-Day Revolving Credit Facility	1.17% - 4.00%	1.82%
Multi-Year Revolving Credit Facility	1.67% - 4.00%	1.71%
Interim Term Loan	1.72% - 1.78%	1.76%

9. MINORITY INTEREST AND MEMBERS' EQUITY

Minority interest

Minority interest represents third-party unitholders' and joint venture participants' ownership interests in the net assets of certain of our subsidiaries at March 31, 2004. The following table shows the components of minority interest at March 31, 2004:

EPD's limited partners:	
Non-affiliates of EPGP Members	$ 1,293,515
Affiliates of EPGP Members	371,322
Joint venture partners	88,531
	$ 1,753,368

The minority interest attributable to EPD's limited partners primarily consists of EPD common units held by the public, Shell and affiliates of EPGP. The minority interest attributable to joint venture partners is primarily attributable to our partners in Seminole, Wilprise, BEF and the Mid-America pipeline system. For financial reporting purposes, the assets and liabilities of our subsidiaries are consolidated with those of our own with any outside investor's ownership interest in our consolidated balance sheet amounts shown as minority interest.

Members' Equity

At March 31, 2004, DFI owned 95%, and Dan Duncan, LLC owned 5% of the membership interests of the Company. Earnings and cash distributions are allocated to Member capital accounts in accordance with their respective ownership percentages.

10. RELATED PARTY INFORMATION

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is majority-owned and controlled by Dan L. Duncan, who is one of our directors and Chairman of our Board of Directors. In addition, our remaining executive and other officers are employees of EPCO, including O.S. Andras who is our President and Chief Executive Officer and one of our directors.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the EPD units held by EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan’s family. EPCO and Dan Duncan LLC, together, own 100% of our membership interests. Collectively, EPCO, Dan L. Duncan, the Duncan Family 1998 Trust and the Duncan Family 2000 Trust owned 54.6% of EPD’s partnership interests at March 31, 2004.

Our agreements with EPCO are not the result of arm’s-length transactions, and there can be no assurance that any of the transactions provided for therein are effected on terms at least as favorable to the parties to such agreement as could have been obtained from unaffiliated third parties.

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Prior to January 1, 2004, we reimbursed EPCO for the costs of its employees who performed operating functions for us and for costs related to certain of its management and administrative personnel hired in response to the expansion of our business. In addition, we paid EPCO a monthly fee for services provided by its other management and administrative employees. On January 1, 2004, the Administrative Services Agreement was amended to eliminate the fee portion of this reimbursement and to provide that we reimburse EPCO for all costs related to management or administrative support for us.

We also have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we also buy from and sell to EPCO’s Canadian affiliate certain NGL products.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 31, 2004, Shell owned an approximate 18.3% equity interest in EPD. Shell is one of our largest customers. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

Relationship with unconsolidated affiliates

Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix.

11. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available. These components are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Our reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by our CEO. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our investment in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE and isobutylene). The Other business segment consists of fee-based marketing services and various operational support activities.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

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

	Operating Segments						
	Fractionation	**Pipelines**	**Processing**	**Octane Enhancement**	**Other**	**Adjs. and Elims.**	**Consol. Totals**
Segment assets:							
At March 31, 2004	$ 466,746	$2,178,442	$ 200,838	$ 41,638	$ 23,123	$ 40,834	$2,951,621
Investments in and advances to unconsolidated affiliates (see Note 6):							
At March 31, 2004	89,041	644,252	33,000				766,293
Intangible Assets (see Note 7):							
At March 31, 2004	67,923	9,601	185,938	1,609			265,071
Goodwill (see Note 7):							
At March 31, 2004	81,547	880					82,427

12. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or "trading") purposes.

We recognize our financial instruments on the balance sheet as assets and liabilities based on the instrument's fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in the Statement of Operations and Comprehensive Income for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to price risk, interest rate risk or changes in fair value and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness is recorded into earnings immediately.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our conclusions regarding the application of guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of this guidance.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements (see Note 9). We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis to estimate the expected impact of changes in interest rates on our future cash flows. Our management oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate risks by utilizing interest rate swaps and similar arrangements. The objective of entering into this type of arrangement is to manage debt service costs by converting a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. In general, an interest rate swap requires one party to pay a fixed interest rate on a defined (or "notional") amount while the other party pays a variable rate based on the same notional amount. The notional amount specified in an interest rate swap agreement does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss on these financial instruments is remote, and that if incurred, such losses would be minimal. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt.

Fair value hedges – Interest rate swaps. On January 8, 2004, we entered into three interest rate swap agreements under which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest:

Hedged Fixed Rate Debt	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb.2011	Jan. 2004 to Feb.2011	Feb. 2011	7.50% to 4.6%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb.2013	Jan. 2004 to Feb.2013	Feb. 2013	6.375% to 3.1%	$100 million
Senior Notes C, 6.375% fixed rate, due Feb.2013	Jan. 2004 to Feb.2013	Feb. 2013	6.375% to 3.1%	$100 million

We have designated these interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. These agreements have a combined notional amount of $250 million and match the maturity dates of the underlying debt being hedged. Under the swap agreements, we pay the counterparty a variable rate based on LIBOR (plus an applicable margin) and receive back from the counterparty a fixed rate payment equal to the stated interest rate of the debt being hedged, based on the notional amounts for each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period").

As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense. However, the interest rate swaps effectively converted a portion of the underlying fixed rate debt (i.e., the notional amounts hedged for Senior Notes B and C) into variable rate debt. As a result, interest expense will vary depending on the variable rates payable by us under terms of the swap agreements at the end of each settlement period. To the extent that the variable rate amount payable by us at the end of each settlement period is less than the fixed rate amount receivable from the counterparty, we will amortize the difference ratably to earnings as a reduction in interest expense over the settlement period. If the variable rate payable by us at the end of each settlement period is more than the fixed rate amount receivable from the counterparty, we would amortize this difference ratably to earnings as an increase in interest expense over the settlement period.

Total fair value of the interest rate swaps at March 31, 2004 was approximately $6.4 million with an offsetting increase in fair value of the underlying debt.

Cash flow hedges – Forward starting interest rate swaps. On March 17, 2004, we entered into four forward starting interest rate swap transactions with original maturities of September 30, 2004. A forward starting swap is an agreement that effectively hedges the price on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to effectively hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of debt to refinance the existing debt of GulfTerra after the proposed merger is completed (see Note 4). The forward starting interest rate swaps have been designated as cash flow hedges under SFAS No. 133. The notional amount of the anticipated debt issuances was $2 billion.

On April 23, 2004, we elected to terminate these financial instruments in order to monetize the then current value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. This amount will be amortized over the life of the anticipated debt (when issued) as a reduction to interest expense. The following table shows the portfolio of forward starting swaps categorized by the term of the underlying anticipated debt offering:

Term of Anticipated Debt Offering (or forecasted transaction)	**Notional Amount of Anticipated Debt covered by Forward Starting Swaps**	**Cash Received upon Settlement of Forward Starting Swaps in April 2004**
Five year debt instrument	$ 500.0	$ 18.7
Ten year debt instrument	500.0	26.1
Fifteen year debt instrument	500.0	29.4
Thirty year debt instrument	500.0	30.3
Total	$ 2,000.0	$ 104.5

The non-cash fair value of the forward starting interest rate swaps at March 31, 2004 was $17.0 million and was recorded as a component of other comprehensive income. When the $104.5 million cash settlement is recorded during the second quarter of 2004, it will replace the $17.0 non-cash fair value amount in other comprehensive income.

Commodity risk hedging program

The prices of natural gas, NGLs, petrochemical products and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment's activities, we may enter into various commodity financial instruments. The primary purpose of these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are part of our Fractionation segment. In our Pipelines segment, we utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges or pays certain of its customers for natural gas. Lastly, we do not employ commodity financial instruments in our fee-based marketing business classified under the Other segment.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by management. We enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Management oversees our strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 (as amended and interpreted). In those situations where the financial instrument does not qualify for hedge accounting treatment, the instrument is accounted for using mark-to-market accounting, which results in a degree of non-cash earnings volatility that is dependent upon changes in the commodity prices underlying these financial instruments. Even though these financial instruments may not qualify for hedge accounting treatment under SFAS No. 133, we view such contracts as hedges since this was the intent when we entered into such positions. Upon entering into such positions, our expectation is that the economic performance of these instruments will mitigate (or offset) the commodity risk being addressed. The specific accounting for these contracts; however, is consistent with the requirements of SFAS No. 133.

The fair value of our commodity financial instrument portfolio at March 31, 2004 and the results of our commodity hedging activities for the three months ended March 31, 2004 were both nominal amounts. During the first quarter of 2004, we utilized a limited number of commodity financial instruments.

13. SIGNIFICANT CONCENTRATIONS OF RISK

Nature of Operations

General. Our Company is subject to a number of risks inherent in the industry in which it operates, including fluctuating gas and product prices. Our financial condition and results of operations depend significantly on the demand for NGLs and the costs involved in their production. These NGL, natural gas and other related prices are subject to fluctuations in response to changes in supply, market uncertainty, weather and a variety of additional factors that are beyond our control.

In addition, we must obtain access to new natural gas volumes along the Gulf Coast of the United States for our processing business in order to maintain or increase gas plant processing levels to offset natural declines in field reserves. The number of wells drilled by third parties to obtain new volumes will depend on, among other factors, the price of gas and oil, the energy policy of the federal government and the availability of foreign oil and gas, none of which is in our control.

The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing and in the production of motor gasoline and as fuel for residential and commercial heating. A reduction in demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, governmental regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could have a negative impact on our results of operation. A material decrease in natural gas production or crude oil refining, as a result of depressed commodity prices or otherwise, or a decrease in imports of mixed butanes, could result in a decline in volumes processed and sold by us.

MTBE. We own a 66.7% interest in BEF, which owns a facility that currently produces MTBE, a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. We operate the facility, which is located within our Mont Belvieu complex.

The production of MTBE is primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. In recent years, MTBE has been detected in water supplies. The major source of ground water contamination appears to be leaks from underground storage tanks. As a result of environmental concerns, several states have enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. In addition, federal legislation has been drafted to ban MTBE and replace the oxygenate with renewable fuels such as ethanol.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against BEF. It is possible, however, that MTBE manufacturers such as BEF could ultimately be added as defendants in such lawsuits or in new lawsuits.

As a result of these developments, we are currently in the process of modifying the facility to also produce iso-octane, a motor gasoline octane enhancement additive derived from isobutane. We expect iso-octane to be in demand by refiners to replace the volume of octane that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. The facility will continue to produce MTBE as market conditions warrant and will be capable of producing either MTBE or iso-octane once the plant modifications are complete. Depending on the outcome of various factors (including pending federal legislation) the facility may be further modified in the future to produce alkylate.

As noted above, MTBE demand is primarily linked to reformulated motor gasoline requirements in certain urban areas of the United States designated as carbon monoxide and ozone non-attainment areas by the federal Clean Air Act Amendments of 1990. Motor gasoline demand in turn is affected by many factors, including the price of motor gasoline (which is generally dependent upon crude oil prices) and overall economic conditions. Sunoco Inc. (“Sun”) is obligated to purchase all of BEF’s MTBE production at spot-market related prices through September 2004. Sun uses the MTBE it purchases from BEF either (i) to satisfy its own reformulated gasoline blending requirements in the eastern United States markets it serves, or (ii) as a commodity offered for resale to others.

BEF is exposed to commodity price risk due to the market-pricing provisions of the Sun agreement. Traditionally, MTBE prices are stronger during the April to September period of each year, which corresponds with the summer driving season. Future MTBE prices will be influenced by the timing and extent of federal and state legislation to ban or limit the use of MTBE.

Credit risk

A substantial portion of our revenues are derived from various companies in the NGL and petrochemical industry, located in the United States. This concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Counterparty risk

From time to time, we have credit risk with our counterparties in terms of settlement risk associated with its financial instruments (which includes accounts receivable). On all transactions where we are exposed to credit risk, we analyze the counterparty’s financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. In December 2001, Enron Corp., or “Enron”, filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Within our allowance for doubtful accounts is an $8.6 million reserve for amounts owed to us by Enron and its affiliates. Affiliates of Enron were our counterparty to various past financial instruments, which were guaranteed by Enron. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable.

14. SUBSEQUENT EVENTS

Interest Rate Hedging Program

In March 2004, we entered into forward starting interest rate swaps in anticipation of entering into permanent debt financing for the proposed merger with GulfTerra. In late April 2004, we terminated these arrangements and received approximately $104.5 million in cash. This amount will be amortized as a reduction in interest expense over the life of the future planned debt issuances, which are forecasted to take place during the second half of 2004. Please see Note 13 for additional information regarding these financial instruments.

May 2004 equity offering

In May 2004, EPD sold 17,250,000 common units (including 2,250,000 common units issued in connection with the underwriters’ overallotment) to the public at an offering price of $21.00 per unit. Net proceeds from this offering, including our proportionate net capital contribution of $7.1 million, were approximately $353.1 million after deducting applicable underwriting discounts, commissions and offering expenses of approximately $16 million. The net proceeds from this offering, including our proportionate net capital contribution, were used to repay in full our $225 million Interim Term Loan and to temporarily reduce borrowings under our revolving credit facilities.