**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): December 31, 2003

**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** |
| (Address of Principal Executive Offices) | (Zip Code) |

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

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**Item 5. OTHER EVENTS.**

We are filing the audited consolidated balance sheet of Enterprise Products GP, LLC as of December 31, 2003, 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.

23.1 Consent of Deloitte & Touche LLP.
99.1 Audited Consolidated Balance Sheet of Enterprise Products GP, LLC as of December 31, 2003.

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## 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: March 22, 2004

By: /s/ Michael J. Knesek

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

**EXHIBIT 23.1**

**INDEPENDENT AUDITORS' CONSENT**

We consent to the incorporation by reference in Enterprise Products Partners L.P.'s (i) Registration Statement No. 333-36856 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-102778 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-3; (iii) Registration Statement No. 333-82486 of Enterprise Products Partners L.P. on Form S-8; and (iv) Registration Statement No. 333-107073 of Enterprise Products Partners L.P. on Form S-3D of our report dated March 16, 2004, relating to the consolidated balance sheet of Enterprise Products GP, LLC at December 31, 2003 appearing in the Form 8-K of Enterprise Products Partners L.P. dated March 22, 2004.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 22, 2004

**EXHIBIT 99.1**

# Enterprise Products GP, LLC

*Consolidated Balance Sheet as of December 31, 2003*
*and Independent Auditors' Report*

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**ENTERPRISE PRODUCTS GP, LLC**

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**INDEPENDENT AUDITORS' REPORT**

To Enterprise Products GP, LLC:
Houston, Texas

We have audited the accompanying consolidated balance sheet of Enterprise Products GP, LLC (the "Company") as of December 31, 2003. This financial statement is the responsibility of the Company's management. Our responsibility is to express an opinion on this consolidated financial statement based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated balance sheet. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated balance sheet presentation. We believe that our audit of the consolidated balance sheet provides a reasonable basis for our opinion.

In our opinion, such consolidated balance sheet presents fairly, in all material respects, the financial position of the Company as of December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 16, 2004



**ENTERPRISE PRODUCTS GP, LLC**
**CONSOLIDATED BALANCE SHEET**
**AT DECEMBER 31, 2003**
**(Dollars in thousands)**

| | 2003 |
|---|---|
| **ASSETS** | |
| **Current Assets** | |
| Cash and cash equivalents (includes restricted cash of $13,851) | $ 44,317 |
| Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,423 | 462,198 |
| Accounts receivable - affiliates | 335 |
| Inventories | 150,161 |
| Prepaid and other current assets | 30,160 |
| Total current assets | 687,171 |
| **Property, Plant and Equipment, Net** | 2,963,505 |
| **Investments in and Advances to Unconsolidated Affiliates** | 767,759 |
| **Intangible assets, net of accumulated amortization of $40,371** | 268,893 |
| **Goodwill** | 82,427 |
| **Deferred Tax Asset** | 10,437 |
| **Long-Term Receivables** | 5,454 |
| **Other Assets** | 17,156 |
| **Total** | $ 4,802,802 |
| **LIABILITIES AND MEMBERS' EQUITY** | |
| **Current Liabilities** | |
| Current maturities of debt | $ 240,000 |
| Accounts payable - trade | 68,384 |
| Accounts payable - affiliates | 40,086 |
| Accrued gas payables | 622,982 |
| Accrued expenses | 24,696 |

| | |
|---|---|
| Accrued interest | 45,350 |
| Other current liabilities | 57,900 |
| Total current liabilities | 1,099,398 |
| **Long-Term Debt** | 1,899,548 |
| **Other Long-Term Liabilities** | 14,443 |
| **Minority Interest** | 1,752,970 |
| **Commitments and Contingencies** | |
| **Members' Equity** | 36,443 |
| **Total** | $ 4,802,802 |

See notes to consolidated balance sheet.



**ENTERPRISE PRODUCTS GP, LLC**
**NOTES TO 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.

At December 31, 2003, EPC Partners II, Inc. ("EPCP II", a subsidiary of EPCO) owned 95%, and Dan Duncan, LLC owned 5% of the membership interests of EPGP. EPCP II and Dan Duncan, LLC are hereafter collectively referred to as the "Members." Enterprise Products Company ("EPCO") is the ultimate parent of EPCP II and an affiliate of Dan Duncan, LLC.

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. This balance sheet should be read in conjunction with EPD's Form 10-K (Commission File No. 1-14323) for the year ended December 31, 2003.

In December 2003, EPGP restructured its ownership interest in EPD and the Operating Partnership from a 1% ownership interest in EPD and a 1.0101% ownership interest in the Operating Partnership to a 2% ownership interest in EPD. As a result, EPD's effective ownership interest in its Operating Partnership increased from 98.9899% to 100%. The purpose of the restructuring was to simplify and reduce the cost of compliance with Securities and Exchange Commission ("SEC") rules relating to the financial reporting requirements of EPD's subsidiaries.

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.

As a result of EPCP II 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 EPCP II's indirect control of EPD through its majority common unit holdings, gives EPGP the ability to exercise control over EPD. All significant 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 10 for additional details of minority interest in our consolidated subsidiaries.

The following table shows the consolidation of EPD's consolidated balance sheet at December 31, 2003 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 $13,851 at December 31, 2003) | $ 44,317 | | | $ 44,317 |
| Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,423 at December 31, 2003 | 462,198 | | | 462,198 |
| Accounts receivable - affiliates | 347 | $ (2,053) | $ 2,041 | 335 |
| Inventories | 150,161 | | | 150,161 |
| Prepaid and other current assets | 30,160 | | | 30,160 |
| Total current assets | 687,183 | (2,053) | 2,041 | 687,171 |
| **Property, Plant and Equipment, Net** | 2,963,505 | | | 2,963,505 |
| **Investments in and Advances to Unconsolidated Affiliates** | 767,759 | 34,350 | (34,350) | 767,759 |
| **Intangible assets, net of accumulated amortization of $40,371 at December 31, 2003** | 268,893 | | | 268,893 |
| **Goodwill** | 82,427 | | | 82,427 |
| **Deferred Tax Asset** | 10,437 | | | 10,437 |
| **Long-Term Receivables** | 5,454 | | | 5,454 |
| **Other Assets** | 17,156 | | | 17,156 |
| **Total** | $ 4,802,814 | $ 32,297 | $ (32,309) | $ 4,802,802 |
| **LIABILITIES AND PARTNERS' AND MEMBERS' EQUITY** | | | | |
| **Current Liabilities** | | | | |
| Current maturities of debt | $ 240,000 | | | $ 240,000 |
| Accounts payable - trade | 68,384 | | | 68,384 |
| Accounts payable - affiliates | 38,045 | | $ 2,041 | 40,086 |
| Accrued gas payables | 622,982 | | | 622,982 |
| Accrued expenses | 24,695 | $ 1 | | 24,696 |
| Accrued interest | 45,350 | | | 45,350 |
| Other current liabilities | 57,420 | 480 | | 57,900 |
| Total current liabilities | 1,096,876 | 481 | 2,041 | 1,099,398 |
| **Long-Term Debt** | 1,899,548 | | | 1,899,548 |
| **Other Long-Term Liabilities** | 14,081 | 362 | | 14,443 |
| **Minority Interest** | 86,356 | | 1,666,614 | 1,752,970 |
| **Commitments and Contingencies** | | | | |
| **Partners' Equity** | | | | |
| Limited partners | 1,683,133 | | (1,683,133) | |
| General partner | 34,349 | | (34,349) | |
| Treasury units | (16,519) | | 16,519 | |
| Accumulated Other Comprehensive Income | 4,990 | | (4,990) | |
| Total Partners' Equity | 1,705,953 | | (1,705,953) | |
| **Members' Equity** | | 31,454 | 4,989 | 36,443 |
| **Total** | $ 4,802,814 | $ 32,297 | $ (32,309) | $ 4,802,802 |

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The following is a summary of our significant consolidated accounting policies. In general, these policies primarily relate to transactions recorded by EPD and its subsidiaries. The policies described below are those applicable to our consolidated balance sheet at December 31, 2003.

**ALLOWANCE FOR DOUBTFUL ACCOUNTS** is generally determined as a percentage of revenues for the last twelve months. Our procedure for recording an allowance for doubtful accounts is based on historical experience, financial stability of our customers and levels of credit granted to customers. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and those experiencing financial uncertainties. We routinely review our estimates in this area to ascertain that we have recorded sufficient reserves to cover forecasted losses.

**ASSET RETIREMENT OBLIGATIONS** are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development, and/or normal operation. In determining asset retirement obligations, we must identify those legal obligations that we are required to settle as result of existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

Statement of Financial Accounting Standards ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*," addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and related asset retirement costs. It requires us to record the fair value of an asset retirement obligation (a liability) in the period in which it is incurred. When a liability is recorded, we would capitalize the cost of the liability by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we would either settle the obligation for its recorded amount or incur a gain or loss upon settlement. We adopted SFAS No. 143 as of January 1, 2003. See Note 6 for information relating to our implementation of this standard.

**CASH AND CASH EQUIVALENTS** represent cash on deposit and other investments that are readily convertible into cash and purchased with original maturities of three months or less.

**DEFERRED TAX** assets and liabilities are recognized for temporary differences between the underlying assets and liabilities for financial reporting and tax purposes. Federal and state income taxes are applicable primarily to Seminole Pipeline Company, which is a corporation and a subsidiary of the Operating Partnership. In general, EPD's limited partnership structure is not subject to federal income taxes. As a result, its earnings and losses for federal income tax purposes are included in the tax returns of its partners.

On a standalone basis, EPGP (a limited liability company) was organized as a pass-through entity for federal income tax purposes. As a result, for federal income tax purposes, the Members are individually responsible for taxes of their allocable share of the taxable income of EPGP.

**DOLLAR AMOUNTS** presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

**ENVIRONMENTAL COSTS** for remediation are accrued based on the estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate costs to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred, and expenditures to mitigate or prevent future environmental contamination are capitalized. At December 31, 2003, accrued environmental liabilities to mitigate or eliminate future environmental contamination were not significant to the consolidated balance sheet. Our estimated liability for environmental remediation is not discounted.

**EXCESS COST OVER UNDERLYING EQUITY IN NET ASSETS** (or "excess cost") denotes the excess of our cost (or purchase price) over our underlying equity in the net assets of our investees. We have excess cost associated with certain of our equity method investments. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities.



We evaluate equity method investments (which include excess cost amounts attributable to tangible or intangible assets) 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. Examples of such events or changes in circumstances include continuing operating losses of the investee or long-term negative changes in the investee's industry. In the event that we determine that the loss in value of an investment is other than a temporary decline, we would record a charge to earnings to adjust the carrying value to fair value. See Note 7 for a further discussion of our excess cost amounts.

**EXCHANGES** are movements of NGL and petrochemical products and natural gas between parties to satisfy timing and logistical needs of the parties. Volumes borrowed from us under such agreements are included in accounts receivable, and volumes loaned to us under such agreements are accrued as a liability in accrued gas payables.

**FINANCIAL INSTRUMENTS** such as swaps, forward and other contracts to manage the price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions are used by Enterprise. We recognize our transactions 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. Changes in 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 related results of the hedge item in the income statement 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 occurs. 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 commodity or interest rate risk 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. See Note 14 for a further discussion of our financial instruments.

**GOODWILL** consists of the excess of amounts we paid for businesses and assets over the respective fair value of the underlying net assets purchased (see Note 8). Since adopting SFAS No. 142, "*Goodwill and Other Intangible Assets*", on January 1, 2002, our goodwill amounts are no longer amortized but will be assessed annually for recoverability. In addition, we will periodically review the reporting units to which the goodwill amounts relate if impairment indicators are evident. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit, including its related goodwill, will be calculated and compared to its combined book value. If the fair value of the reporting unit exceeds its book value, goodwill is not considered impaired and no adjustment to earnings would be required. Should the fair value of the reporting unit (including its goodwill) be less than its book value, a charge to earnings would be recorded to adjust goodwill to its implied fair value.

**INVENTORIES** primarily consist of NGL, petrochemical and natural gas volumes and are valued at the lower of average cost or market (see Note 5). Shipping and handling charges directly related to volumes we purchase or to which we take ownership are capitalized as costs of inventory. As these inventories are sold and delivered out of inventory, the average cost of these products (which includes freight-in charges which have been capitalized) are charged to current period operating costs and expenses. Shipping and handling charges for products we sell and deliver to customers are charged to operating costs and expenses as incurred.

**INTANGIBLE ASSETS** consist primarily of the estimated value of contract rights we own arising from agreements with customers (see Note 8). A contract-based intangible asset with a finite useful life is amortized over its estimated useful life, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of the entity. It is based on an analysis of all pertinent factors including (a) the expected use of the asset by the entity, (b) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (c) any legal, regulatory or contractual provisions, including renewal or extension periods that would not cause



substantial costs or modifications to existing agreements, (d) the effects of obsolescence, demand, competition, and other economic factors and (e) the level of maintenance required to obtain the expected future cash flows.

**LONG-LIVED ASSETS** (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 "*Accounting for the Impairment or Disposal of Long-Lived Assets*." Under SFAS No. 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows.

**PROPERTY, PLANT AND EQUIPMENT** is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Maintenance, repairs and minor renewals are charged to operations as incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts. Any gain or loss on disposition is included in income.

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to the Company. See Note 6 for additional information regarding our property, plant and equipment.

We use the expense-as-incurred method for our planned major maintenance activities. Prior to January 1, 2004, Belvieu Environmental Fuels ("BEF") used the accrue-in-advance method for its planned major maintenance costs. On January 1, 2004, BEF elected to change its method of accounting for these costs to the expense-as-incurred method. The cumulative effect on EPGP's members' equity on January 1, 2004 of this change in accounting method is an increase in members' equity of less than $0.1 million.

**RESTRICTED CASH** includes amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for physical purchase transactions made on the New York Merchantile Exchange ("NYMEX") exchange.

**USE OF ESTIMATES AND ASSUMPTIONS** by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements are required for the preparation of financial statements in conformity with accounting principles generally accepted in the United States of America. Our actual results could differ from these estimates.

## 3. OTHER RECENTLY ISSUED ACCOUNTING STANDARDS AND GUIDANCE

Other than those discussed in our general accounting policies (see Note 2), we adopted the following accounting guidance during 2003:

- *SFAS No. 145,* "*Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.*" We adopted provisions of this standard as of January 1, 2003. This statement revised accounting guidance related to the extinguishment of debt and accounting for certain lease transactions. It also amended other accounting literature to clarify its meaning, applicability and to make various technical corrections. Our adoption of this standard has had no material impact on our financial statements.

- *SFAS No. 149,* "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities.*" This statement amends and clarifies accounting guidance for derivative instruments, including certain derivative



instruments embedded in other contracts, and for hedging activities under SFAS No. 133. This statement is effective for contracts entered into or modified after June 30, 2003, for hedging relationships designated after June 30, 2003, and to certain preexisting contracts. We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

- *SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*." This standard establishes classification and measurement standards for financial instruments with characteristics of both liabilities and equity. It requires an issuer of such financial instruments to reclassify the instrument from equity to a liability or an asset. The effective date of this standard for us was July 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

- *FASB Interpretation("FIN") No. 45,* "*Guarantor's Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others*." We implemented this Financial Accounting Standards Board ("FASB") interpretation as of December 31, 2002. This interpretation of SFAS No. 5, 57 and 107, and rescission of FASB Interpretation No. 34 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. We have provided the information required by this interpretation under Note 9.

- *FIN 46,* "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*." This interpretation of Accounting Research Bulletin ("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 financial statements.

## 4. BUSINESS COMBINATIONS

During 2003, the Operating Partnership acquired EPIK's remaining 50% ownership interest, the Port Neches Pipeline, an additional 33.3% interest in BEF, an additional 37.4% interest in Wilprise Pipeline Company, LLC ("Wilprise") and the remaining capital stock of Olefins Terminal Corporation ("OTC"). We also made minor adjustments to the allocation of the purchase price the Operating Partnership paid to acquire indirect interests in Mid-America and Seminole pipelines. The total cost of these acquisitions and other adjustments was $37.3 million.

**Proposed Merger with GulfTerra**

On December 15, 2003, EPD and certain of our affiliates, El Paso, and GulfTerra Energy Partners, L.P. ("GulfTerra") and certain of its affiliates entered into a series of agreements under which GulfTerra would merge with a subsidiary of EPD. Formed in 1993, GulfTerra is a publicly traded limited partnership (NYSE symbol, "GTM") that manages a portfolio of interests and assets relating to the midstream energy sector. El Paso is the ultimate parent of GulfTerra's general partner and owns a 31.8% limited partner interest in GulfTerra. In general, GulfTerra's business lines include:

- Ownership or interests in over 15,700 miles of natural gas pipeline systems. These pipeline systems include gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants located in Louisiana, New Mexico, Texas and Colorado;
- Ownership in over 1,000 miles of intrastate NGL gathering and transportation pipelines and four NGL fractionation plants located in Texas. GulfTerra also owns interests in three offshore oil pipeline systems, which extend over 340 miles, owns a 3.3 million barrel ("MMBbl") propane storage and leaching business located in Mississippi and owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls;

- Ownership in two salt dome natural gas storage facilities located in Mississippi that have a combined current working capacity of 13.5 billion cubic feet ("Bcf"). In addition, GulfTerra has the exclusive right to use a natural gas storage facility located in Wharton, Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf;
- Interests in six multi-purpose offshore hub platforms in the Gulf of Mexico that were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities; and
- Interests in four oil and natural gas producing properties located in waters offshore Louisiana. Production is gathered, transported, and processed through GulfTerra's pipeline systems and platform facilities, and sold to various third parties and El Paso.

GulfTerra is one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and in the San Juan Basin, which covers a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah.

The proposed merger is a three-step process outlined as follows:

- *Step One*. On December 15, 2003, our Operating Partnership purchased a 50% membership interest in GulfTerra's general partner (GulfTerra Energy Company, L.L.C. or "GulfTerra GP") for $425 million. This investment is accounted for using the equity method. 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 we refer to as Step Two and Three, do not occur.

- *Step Two*. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, EPD 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 our company. Step Two of the proposed merger includes the following transactions:

  - El Paso's contribution to us of their remaining 50% interest in GulfTerra GP for a 50% interest in us, and the subsequent capital contribution by us of such 50% interest in GulfTerra GP to EPD (without increasing our interest in EPD's earnings or cash distributions).

  - EPD's purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million; and

  - The exchange of each remaining GulfTerra common unit for 1.81 EPD common units, resulting in the issuance of approximately 103 million EPD common units to GulfTerra unitholders.

- *Step Three*. Immediately after Step Two is completed, EPD expects to acquire nine cryogenic natural gas processing plants, one natural gas gathering system, one natural gas treating plant, and a small natural gas liquids connecting pipeline from El Paso for $150 million. We refer to the assets that EPD will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three EPD would pay or grant is approximately $3.9 billion. For a period of three years following the closing of the proposed merger, El Paso will provide 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 of such services (excluding any overhead costs). El Paso will make transition support payments to EPD in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in 12 equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

We are working to complete the merger as soon as possible. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both EPD and GulfTerra and the expiration 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 to the merger will be satisfied, we expect to complete the merger in the second half of 2004.



To review a copy of the merger agreement and related transaction documents, please read EPD's Current Report on Form 8-K filed with the SEC on December 15, 2003.

## 5. INVENTORIES

Our inventories were as follows at December 31, 2003:

| | | |
|---|---|---|
| Working inventory | $ | 135,451 |
| Forward-sales inventory | | 14,710 |
| Inventory | $ | 150,161 |

A description of each inventory is as follows:

- 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. This inventory is valued at the lower of average cost or market, with "market" being determined by industry-related posted prices such as those published by Oil Price Information Service ("OPIS") and Chemical Market Associates, Inc. ("CMAI").
- The forward-sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts and is valued at the lower of average cost or market, with "market" being defined as the weighted-average sales price for NGL volumes to be delivered in future months on the forward sales contracts.

In general, our inventory values reflect amounts we have paid for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection and demurrage charges and other handling and processing costs. In those instances where we take ownership of inventory volumes through in-kind and similar arrangements (as opposed to actually purchasing volumes for cash from third parties), these volumes are valued at market-related prices during the month in which they are acquired. Like the third-party purchases described above, we inventory the various ancillary costs such as freight-in and other handling and processing amounts associated with owned volumes obtained through our in-kind and similar contracts.

Due to fluctuating market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market ("LCM") adjustments when the cost of our inventories exceed their net realizable value. For the year ended December 31, 2003, we recognized LCM adjustments of approximately $16.9 million. The majority of these write-downs were taken against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated (or in some cases, offset). See Note 14 for a description of our commodity hedging activities.



## 6. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation were as follows at December 31, 2003:

| | Estimated Useful Life in Years | |
|---|---|---|
| Plants and pipelines (1) | 5-35 (4) | $ 3,214,463 |
| Underground and other storage facilities (2) | 5-35 (5) | 288,199 |
| Transportation equipment (3) | 3-10 | 5,676 |
| Land | | 23,447 |
| Construction in progress | | 74,431 |
| Total | | 3,606,216 |
| Less accumulated depreciation | | 642,711 |
| Property, plant and equipment, net | | $ 2,963,505 |

(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).

*Asset retirement obligations*. SFAS No. 143 establishes accounting standards for the recognition and measurement of an asset retirement obligation ("ARO") liability and the associated asset retirement cost. Under the implementation guidelines of SFAS No. 143, we reviewed our long-lived assets for ARO liabilities and identified such liabilities in several operational areas. These include ARO liabilities related to (i) right-of-way easements over property not owned by us and (ii) regulatory requirements triggered by the abandonment or retirement of certain currently operated facilities.

As a result of our analysis of identified ARO's, we were not required to recognize such potential liabilities. Our rights under the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently expect to renew all such easement agreements and to use these properties for the foreseeable future. Therefore, an ARO liability is not estimable for such easements. Should we decide not to renew these right-of-way agreements, an ARO liability would be recorded at that time. We also identified potential ARO liabilities arising from regulatory requirements related to the future abandonment or retirement of certain currently operated facilities. At present, we currently have no intention or legal obligation to abandon or retire such facilities. An ARO liability would be recorded if future abandonment or retirement of such facilities occurred.

Certain Gulf of Mexico natural gas pipelines owned by our equity method investees Starfish Pipeline Company, LLC ("Starfish"), Neptune Pipeline Company, LLC ("Neptune") and Nemo Gathering Company, LLC ("Nemo") have identified ARO's relating to regulatory requirements. At present, these entities have no plans to abandon or retire their major transmission pipelines; however, there are plans to retire certain minor gas gathering lines periodically through 2013. Should the management of these companies decide to abandon or retire their major transmission pipelines, an ARO liability would be recorded at that time. With regard to the minor gas gathering pipelines scheduled for retirement, Starfish and Neptune collectively recorded ARO liabilities during 2003 totaling $2.8 million (on a gross basis).



## 7. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for under 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 our business segments, see Note 13.

*Fractionation segment*

At December 31, 2003, the Fractionation segment included the following unconsolidated affiliates accounted for using the equity method:

- *Baton Rouge Fractionators LLC* ("BRF") – an approximate 32.3% interest in an NGL fractionator located in southeastern Louisiana.
- *Baton Rouge Propylene Concentrator, LLC* ("BRPC") – a 30.0% interest in a propylene fractionator located in southeastern Louisiana.
- *K/D/S Promix LLC* ("Promix") – a 33.3% interest in an NGL fractionator and related storage and pipeline assets located in south Louisiana.
- *La Porte Pipeline Company, L.P.* and *La Porte Pipeline GP, LLC* (collectively "La Porte") – an aggregate 50% interest in a private polymer grade propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas. We do not exercise management control over La Porte and, therefore, are precluded from consolidating its financial statements with our financial statements.

In November 2003, the Operating Partnership purchased the remaining 50% of outstanding common stock of Olefins Terminal Corporation ("OTC") from Valero. As a result, OTC became a wholly owned subsidiary of the Operating Partnership. See Note 4 for additional information regarding our business combinations.

*Pipelines segment:*

At December 31, 2003, our Pipelines operating segment included the following unconsolidated affiliates accounted for using the equity method:

- *Tri-States NGL Pipeline LLC* ("Tri-States") – an aggregate 50% interest in an NGL pipeline system located in Louisiana, Mississippi and Alabama. In October 2003, the Operating Partnership purchased an additional 16.7% interest in Tri-States from Williams. We do not exercise management control over Tri-States and are precluded from consolidating its financial statements with our financial statements.
- *Belle Rose NGL Pipeline LLC* ("Belle Rose") – a 41.7% interest in an NGL pipeline system located in south Louisiana.
- *Dixie Pipeline Company* ("Dixie") – an aggregate 19.9% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina.
- *Starfish Pipeline Company, LLC* ("Starfish") – a 50% interest in the Stingray natural gas pipeline and related dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana. We do not exercise management control over Starfish and are precluded from consolidating its financial statements with our financial statements.
- *Neptune Pipeline Company, L.L.C.* ("Neptune") – a 25.7% interest in the Manta Ray and Nautilus natural gas pipeline systems owned by Manta Ray Offshore Gathering Company, LLC and Nautilus Pipeline Company LLC located in the Gulf of Mexico offshore Louisiana.
- *Nemo Gathering Company, LLC* ("Nemo") – a 33.9% interest in the Nemo natural gas pipeline located in the Gulf of Mexico offshore Louisiana.
- Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp. (collectively, "Evangeline") – an approximate 49.5% aggregate interest in a natural gas pipeline system located in south Louisiana.
- *GulfTerra Energy Company, L.L.C.* ("GulfTerra GP") – a 50% interest in GulfTerra GP, which owns a 1.0% general partner interest in GulfTerra. The Operating Partnership purchased this interest from El Paso on December 15, 2003 for $425 million. Our purchase of this interest is Step One of EPD's proposed merger with GulfTerra. See Note 4 for additional information regarding this proposed business combination. We do not exercise management control over GulfTerra GP and are precluded from consolidating its financial statements with our financial statements.

In March 2003, the Operating Partnership purchased the remaining ownership interests in EPIK Terminalling L.P and EPIK Gas Liquids, LLC (collectively, “EPIK”), at which time EPIK became a consolidated subsidiary of ours. In October 2003, the Operating Partnership purchased an additional 37.4% interest in Wilprise Pipeline Company, LLC (“Wilprise”), at which time it became a 74.7% consolidated subsidiary of ours. See Note 4 for additional information regarding our business combinations.

*Octane Enhancement segment:*

In September 2003, the Operating Partnership acquired an additional 33.3% interest in *Belvieu Environmental Fuels* (“BEF”), which owns a facility that currently produces methyl tertiary butyl ether (“MTBE”), a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. Due to this acquisition, BEF became a majority-owned consolidated subsidiary of ours on September 30, 2003. Previously, BEF was accounted for as an equity-method unconsolidated affiliate.

As a result of declining domestic demand and a prolonged period of weak MTBE production economics, several of BEF’s competitors announced their withdrawal from the marketplace during 2003. Due to the deteriorating business environment and outlook and the completion of its preliminary engineering studies regarding conversion alternatives, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in a non-cash asset impairment charge of $67.5 million. Our share of this loss was $22.5 million.

BEF’s assets were written down to fair value, which was determined by independent appraisers using present value techniques. The impaired assets principally represent the plant facility and other assets associated with MTBE production. The fair value analysis incorporates probability-weighted cash flow for future courses of action being taken (or contemplated to be taken) by BEF management, including modification of the facility to produce iso-octane and alkylate. If the underlying assumptions in the fair value analysis change resulting in expected future cash flows being less than the new carrying value of the facility, additional impairment charges may result in the future. See Note 15 for additional information regarding risks associated with our investment in BEF.

*Processing segment:*

At December 31, 2003, our investments in and advances to unconsolidated affiliates also includes *Venice Energy Services Company, LLC* (“VESCO”). The VESCO investment consists of a 13.1% interest in a company owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in the Gulf of Mexico. We account for this investment using the cost method.



The following table shows our investments in and advances to unconsolidated affiliates at December 31, 2003:

| | **Ownership Percentage** | |
|---|---|---|
| Accounted for on equity basis: | | |
| Fractionation: | | |
| BRF | 32.3% | $ 27,892 |
| BRPC | 30.0% | 16,584 |
| Promix | 33.3% | 38,903 |
| La Porte | 50.0% | 5,422 |
| Pipeline: | | |
| Tri-States | 50.0% | 44,119 |
| Belle Rose | 41.7% | 10,780 |
| Dixie | 19.9% | 35,988 |
| Starfish | 50.0% | 40,664 |
| Neptune | 25.7% | 74,647 |
| Nemo | 33.9% | 12,294 |
| Evangeline | 49.5% | 2,519 |
| GulfTerra GP (1) | 50.0% | 424,947 |

| | | |
|---|---|---|
| Accounted for on cost basis: | | |
| Processing: | | |
| VESCO | 13.1% | 33,000 |
| Total | | $ 767,759 |

(1) In December 2003, we acquired a 50% interest in the general partner of GulfTerra Energy Partners, L.P. from El Paso.

At December 31, 2003, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $38.6 million.

*Excess cost of unconsolidated affiliates*

Our initial investment in Promix, La Porte, Dixie, 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 of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. The excess cost amounts related to Promix, Neptune, La Porte and Nemo are attributable to the tangible plant and pipeline assets of each entity, and are amortized against equity earnings from these entities in a manner similar to depreciation. The excess cost of Dixie includes amounts attributable to both goodwill and tangible pipeline assets, with the portion assigned to the pipeline assets being amortized in a manner similar to depreciation. The excess cost of GulfTerra GP has been attributed to goodwill and represents our preliminary allocation of the purchase price of this interest pending completion of a fair value analysis which is expected to be completed during the last half of 2004. The goodwill inherent in Dixie's and GulfTerra GP's excess cost is not amortized. To the extent that our preliminary allocation of the excess cost of GulfTerra GP is ultimately attributed to depreciable or amortizable assets, our equity earnings from GulfTerra GP will be reduced.



The following table summarizes our excess cost information at the dates and for the periods indicated:

| | Amort. Periods | Initial Excess Cost attributable to: Tangible assets | Initial Excess Cost attributable to: Goodwill | Unamortized balance at December 31, 2003 |
|---|---|---|---|---|
| Fractionation segment: | | | | |
| Promix | 20 years | $ 7,955 | | $ 6,256 |
| La Porte | 35 years | 873 | | 789 |
| Pipelines segment: | | | | |
| Dixie | 35 years (1) | 28,448 | $ 9,246 | 34,084 |
| Neptune | 35 years | 12,768 | | 11,674 |
| Nemo | 35 years | 727 | | 676 |
| GulfTerra GP | n/a (1) | | 328,214 | 328,214 |

(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.

*Financial Summary*

The following table summarizes the financial position of our significant equity method investments at December 31, 2003.

| | |
|---|---|
| **BALANCE SHEET DATA:** | |
| Current assets | $ 69,340 |
| Property, plant and equipment, net | 724,129 |
| Other assets | 234,953 |
| Total assets | $ 1,028,422 |

| | | |
|---|---|---|
| Current liabilities | $ | 57,693 |
| Other liabilities | | 55,619 |
| Combined equity | | 915,110 |
| Total liabilities and combined equity | $ | 1,028,422 |



## 8. INTANGIBLE ASSETS AND GOODWILL

**Intangible assets**

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

| | At December 31, 2003 | | |
|---|---|---|---|
| | Gross Value | Accum. Amort. | Carrying Value |
| Shell natural gas processing agreement | $ 206,216 | $ (34,063) | $ 172,153 |
| Storage II contracts | 8,127 | (464) | 7,663 |
| Splitter III contracts | 53,000 | (2,902) | 50,098 |
| Toca-Western natural gas processing contracts | 11,187 | (885) | 10,302 |
| Toca-Western NGL fractionation contracts | 20,042 | (1,587) | 18,455 |
| Venice contracts (1) | 6,635 | (136) | 6,499 |
| Port Neches pipeline contracts (2) | 2,400 | (310) | 2,090 |
| BEF UOP License Fee (3) | 1,657 | (24) | 1,633 |
| Total | $ 309,264 | $ (40,371) | $ 268,893 |

(1) Amortization commenced when contracted volumes began to be processed during 2003.
(2) Acquired as a result of our purchase of the Port Neches pipeline in March 2003.
(3) This intangible asset relates to the operations BEF, which we began consolidating on September 30, 2003 as a result of purchasing an additional 33.3% interest.

At December 31, 2003, our intangible assets consisted of:

- The Shell natural gas processing agreement that the Operating Partnership acquired as part of the TNGL acquisition in August 1999. The value of the Shell agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.
- Certain storage and propylene fractionation contracts the Operating Partnership acquired from affiliates of both Valero Energy Corporation and Koch Industries, Inc. (the “Diamond-Koch” acquisitions) in January and February 2002. The values of these contracts are being amortized on a straight-line basis over the 35-year remaining economic life of the assets to which they relate.
- Certain natural gas processing and NGL fractionation contracts the Operating Partnership acquired in connection with the Toca-Western acquisition in June 2002. The Toca-Western natural gas processing contracts are being amortized on a straight-line basis over the expected 20-year economic life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized on a straight-line basis over the expected 20-year remaining life of the assets to which they relate.
- Certain NGL-related contracts related to our ability to take delivery of purity NGL products and mixed NGLs from VESCO at a lower cost than otherwise would have been incurred. The value of these contracts are being amortized on a straight-line basis over the terms of each contract, which approximate 14 years.
- Certain product handling and transportation contracts related to our Port Neches pipeline, the values of which are being amortized on a straight-line basis over the terms of the contracts.
- Certain license fees related to the octane enhancement business of BEF, the operations of which we began consolidating on September 30, 2003. These fees are being amortized over the expected 20-year remaining useful life of the operations to which they relate.

**Goodwill**

Our goodwill is attributable to the excess of the purchase price of an acquired entity over the net amounts assigned to identifiable assets acquired (including identifiable intangible assets) and liabilities assumed. Goodwill is not amortized; however, it is subject to periodic impairment testing. At December 31, 2003, our goodwill amounts were as follows:



- $73.7 million recorded in connection with the Operating Partnership's acquisition of propylene fractionation assets from Diamond-Koch in February 2002. This amount is classified under our Fractionation segment.
- $7.9 million recorded in connection with the Operating Partnership's acquisition of an additional interest in Mont Belvieu Associates in July 2001, which in turn owned an interest in our Mont Belvieu NGL fractionation facility. This amount is classified under our Fractionation segment.
- $0.9 million recorded in connection with the Operating Partnership's acquisition of an additional 37.4% interest in Wilprise in October 2003. This amount is classified under our Pipelines segment.

## 9. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

| | December 31, 2003 |
|---|---|
| Borrowings under: | |
| 364-Day Term Loan, variable rate, repaid during 2003 (1) | |
| Interim Term Loan, variable rate, due the earlier of September 2004 or the date that our proposed merger with GulfTerra is completed (see Note 4) | $ 225,000 |
| 364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity | 70,000 |
| Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2) | 115,000 |
| Senior Notes A, 8.25% fixed rate, due March 2005 | 350,000 |
| Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 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 | 2,144,000 |
| Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt | 1,531 |
| Less unamortized discounts on Senior Notes A, B and D | (5,983) |
| Subtotal long-term debt | 2,139,548 |
| Less current maturities of debt (4) | (240,000) |
| Long-term debt (4) | $ 1,899,548 |
| Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility (2) | $ 1,300 |

(1) We used a combination of proceeds from the issuance of Senior Notes C and D and the January 2003 common unit offering to fully repay this facility in February 2003.

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

(3) As to the assets of our subsidiary, Seminole Pipeline Company, our $2.1 billion in senior indebtedness at December 31, 2003 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 December 31, 2003 reflect the classification of such debt obligations at March 1, 2004. With respect to our 364-Day Revolving Credit Facility, 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.



See Note 12 for our scheduled future maturities of long-term debt at December 31, 2003.

**Parent-subsidiary guarantor relationships**

EPD acts as guarantor of all of its Operating Partnership's consolidated debt obligations, 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 the Operating Partnership owns an effective 78.4% of its capital stock).

**General description of debt**

The following is a summary of the significant aspects of our debt obligations at December 31, 2003.

*Interim Term Loan*. In December 2003, our Operating Partnership entered into a $225 million acquisition-related term loan to partially finance its $425 million purchase of GulfTerra GP (see Note 7). The maturity date of this term loan is the earlier of September 2004 or the date EPD's proposed merger with GulfTerra is completed. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. EPD has guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined in the loan agreement). For information regarding variable-interest rates paid under this term loan agreement, please read "*Information regarding variable-interest rates* paid" within this Note 9.

This term loan agreement contains various covenants related to our Operating Partnership's ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires the Operating Partnership to satisfy certain financial covenants at the end of each fiscal quarter. If an event of default (as defined in the agreement) occurs, the Operating Partnership is prohibited from making distributions to EPD, which, in turn, would impair EPD's ability to make distributions to its partners (including us). As defined in the agreement, the Operating Partnership must maintain a specified level of consolidated net worth and certain financial ratios. We were in compliance with these covenants at December 31, 2003.

*364-Day Revolving Credit Facility*. In October 2003, our Operating Partnership entered into new 364-day revolving credit agreement that contained essentially the same terms as our November 2002 364-Day revolving credit agreement that expired in November 2003. The stand-alone borrowing capacity under the new revolving credit facility is $230 million with the maturity date for any amount outstanding being October 2004. We have the option 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 credit agreement. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to us. EPD has guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined in the loan agreement). We elect the basis of the interest rate at the time of each borrowing. For information regarding variable-interest rates paid under this revolving credit agreement, please read "*Information regarding variable-interest rates paid*" within this Note 9.

This revolving credit agreement contains various covenants similar to those of our Interim Term Loan (please refer to our discussion regarding restrictive covenants of the Interim Term Loan within this "*General description of debt*" section). We were in compliance with these covenants at December 31, 2003.

*Multi-Year Revolving Credit Facility*. In November 2002, our Operating Partnership entered into a five-year revolving credit facility that includes a sublimit of $75 million for standby letters of credit. Currently,



the stand-alone borrowing capacity under this revolving credit facility is $270 million. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to us. EPD has guaranteed repayment of amounts due under this term loan through an unsecured guarantee.

As defined by the agreement, variable interest rates charged under this facility generally bear interest at either, at our election, (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. We elect the basis of the interest rate at the time of each borrowing. For information regarding variable-interest rates paid under this revolving credit agreement, please read "*Information regarding variable-interest rates paid*" within this Note 9.

This revolving credit agreement contains various covenants similar to those of our Interim Term Loan (please refer to our discussion regarding restrictive covenants of the Interim Term Loan within this "*General description of debt*" section). We were in compliance with these covenants at December 31, 2003.

*Senior Notes A, B, C and D*. These fixed-rate notes are an unsecured obligation of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to us. EPD has guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We were in compliance with these covenants at December 31, 2003.

In January 2003, the Operating Partnership issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 2013 ("Senior Notes C"), from which it received net proceeds before offering expenses of approximately $347.7 million. These private placement notes were sold at face value with no discount or premium. We used the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan that we incurred to finance the Mid-America and Seminole acquisitions. In May 2003, the Operating Partnership exchanged 100% of the private placement Senior Notes C for publicly registered Senior Notes C.

In February 2003, the Operating Partnership issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 2033 ("Senior Notes D"), from which it received net proceeds before offering expenses of approximately $489.8 million. These private placement notes were sold at 98.842% of their face amount. We used $421.4 million from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. In addition, we applied $60.0 million of the proceeds to reduce the balance outstanding under the 364-Day Revolving Credit Facility. The remaining proceeds were used for working capital purposes. In July 2003, the Operating Partnership exchanged 100% of the private placement Senior Notes D for publicly registered Senior Notes D.

**Repayment of 364-Day Term Loan**

In July 2002, our Operating Partnership entered into the $1.2 billion senior unsecured 364-Day Term Loan to fund the acquisition of interests in the Mid-America and Seminole pipelines. We used $178.5 million of the $182.5 million in proceeds from EPD's October 2002 equity offering to partially repay this loan. We also used $252.8 million of the $258.1 million in proceeds from EPD's January 2003 equity offering, $347.0 million of the $347.7 million in proceeds from our Operating Partnership's issuance of Senior Notes C and $421.4 million in proceeds from its issuance of Senior Notes D to fully repay the 364-Day Term Loan in February 2003.



**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 during 2003.

| | Range of interest rates paid | Weighted-average interest rate paid |
|---|---|---|
| 364-Day Term Loan (1) | 2.59% - 2.88% | 2.85% |
| 364-Day Revolving Credit Facility | 1.79% - 4.75% | 2.48% |
| Multi-Year Revolving Credit Facility | 1.64% - 4.25% | 1.87% |
| Interim Term Loan | 1.77% - 4.00% | 2.16% |

(1) This facility was fully repaid in February 2003.

**10. 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 our subsidiaries at December 31, 2003. The following table shows the components of minority interest at December 31, 2003:

| | | |
|---|---|---|
| EPD's limited partners: | | |
| Non-affiliates of EPGP Members | $ | 1,244,018 |
| Affiliates of EPGP Members | | 422,596 |
| Joint venture partners | | 86,356 |
| | $ | 1,752,970 |

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 Pipeline Company, 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 December 31, 2003, EPCP II 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.

## 11. RELATED PARTY INFORMATION

**Relationship with EPCO and its affiliates**

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 54.5% of EPD's partnership interests at December 31, 2003.

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.

*Administrative Services Agreement*. As stated previously, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement (formerly the "EPCO Agreement"). Under the terms of the Administrative Services Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs;
- employ the operating personnel involved in our business for which we reimburse EPCO (based upon EPCO's actual salary and related fringe benefits cost);
- allow us to participate as named insureds in EPCO's current insurance program with the costs being allocated among the parties on the basis of formulas set forth in the agreement;
- grant us an irrevocable, non-exclusive worldwide license to all of the EPCO trademarks and trade names used in our business; and
- sublease to the Operating Partnership all of the equipment which it holds pursuant to operating leases relating to an isomerization unit, a deisobutanizer tower, two cogeneration units and approximately 100 railcars for one dollar per year and to assign to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the cash lease payments associated with these assets. The Operating Partnership records the lease payment made by EPCO as a non-cash operating expense offset by a corresponding increase in its partners' equity.

Our payments to EPCO under the Administrative Services Agreement are recorded as general and administrative costs. We reimburse EPCO for all costs it incurs related to administrative personnel it hires in response to our expansion activities. Through December 31, 2003, our reimbursement for all other EPCO administrative personnel working on our behalf was covered by the fixed Administrative Service Fee. During 2003, we paid $17.9 million in such fees to EPCO. To the extent that the Administrative Service Fee did not provide for a full reimbursement of EPCO's actual costs of this remaining group of employees, we recorded a non-cash expense equal to the difference between EPCO's actual cost and the Administrative Service Fee charged (this amount was $0.4 million during 2003). The offset was recorded in partners' equity as a general contribution to the Operating Partnership. Effective January 1, 2004, the Administrative Services Agreement was amended to eliminate the fixed Administrative Service Fee and to provide that the Operating Partnership will reimburse EPCO for all costs of administrative support regardless of whether the costs are related to expansion or other personnel who work on our behalf.

*Other related party transactions with EPCO*. The following is a summary of other significant related party transactions between EPCO and us, including those between EPCO and our unconsolidated affiliates.

- Prior to January 1, 2004, EPCO was the operator of our MTBE facility and Houston Ship Channel NGL import facility. Our Operating Partnership assumed this role on January 1, 2004.
- We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products.
- In the normal course of business, 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 December 31, 2003, Shell owned approximately 18.4% of EPD's Common Units. Shell sold its 30.0% membership interest in us to an affiliate of EPCO in September 2003.

Our largest customer is Shell. For the years ended December 31, 2003, 2002 and 2001, Shell accounted for 5.5%, 7.9% and 10.6%, respectively, of our consolidated revenues. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for 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.

We have completed a number of business acquisitions and asset purchases from Shell since 1999. Among these transactions were:

- the acquisition of natural gas processing and related businesses in 1999 for approximately $528.8 million (this purchase price includes both the $166 million in cash the Operating Partnership paid to Shell and the value of EPD's 41,000,000 Class A special units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene pipeline for $100 million in 2000; and
- the acquisition of Acadian Gas in 2001 for $243.7 million.

Shell is also a partner with us in our Gulf of Mexico natural gas pipeline investments. We also lease from Shell its 45.4% interest in our Splitter I propylene fractionation facility.

**Relationships with Unconsolidated Affiliates**

Our investment in unconsolidated affiliates with industry partners is a vital component of our business strategy. These investments are a means by which we conduct our operations to align our interests with a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. The following summarizes significant related party transactions we have 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. We have also furnished $1.3 million in letters of credit on behalf of Evangeline.
- We pay Dixie transportation fees for propane movements on their system initiated by our NGL marketing activities.
- We pay Promix for the transportation, storage and fractionation of certain of our mixed NGL volumes. In addition, we sell natural gas to Promix for their fuel requirements.

Prior to its becoming a consolidated subsidiary in March 2003, we paid EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers. Also, prior to its becoming a consolidated subsidiary in September 30, 2003, we sold high purity isobutane to BEF as a feedstock and purchased certain of BEF's by-products. We also received transportation fees for BEF's MTBE movements on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.

**12. COMMITMENTS AND CONTINGENCIES**

*Redelivery Commitments*

We store and transport NGL, petrochemical and natural gas volumes for third parties under various processing, storage, transportation and similar agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. We are insured for any physical loss of such volumes due to catastrophic events. At December 31, 2003, NGL and petrochemical volumes aggregating 16.4 million barrels were due to be redelivered to their owners along with 393 billion British thermal units ("BBtus") of natural gas.

*Commitments under equity compensation plans of EPCO*

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us. This includes the costs associated with equity-based awards granted to these employees. At December 31, 2003, there were 1,938,000 options outstanding to purchase common units under EPCO's 1998 Plan that had been granted to employees for which we were responsible for reimbursing EPCO for the costs of such awards. The weighted-average strike price of the unit option awards granted was $16.07 per common unit. At December 31, 2003, 509,000 of these unit options were exercisable. An additional 1,030,000, 374,000 and 25,000 of these unit options will be exercisable in 2004, 2005 and 2006, respectively. Effective January 1, 2004, as these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee.

*Other commitments*

*Long-term debt-related commitments*. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. The table on the following page shows our scheduled future maturities of long-term debt for the periods indicated. See Note 9 for a description of these debt obligations.

*Operating lease commitments*. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. The table on the following page shows the minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated.

*Purchase obligations*. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (unconditional) and that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

- *Product purchase commitments*. We have long and short-term product purchase obligations for NGLs, petrochemicals and natural gas with several third-party suppliers. The purchase prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The table on the following page shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. To the extent that variable price provisions exist in these contracts, our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2003 applied to future volume commitments.

- *Service contract commitments*. We have long and short-term commitments to pay third-party service providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The table on the following page shows our future payment obligations under these service contracts.

- *Capital expenditure commitments*. We have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. The table on the following page shows these combined amounts for the periods indicated:



| | Payment or Settlement due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| **Contractual Obligations** | **Total** | **2004** | **2005** | **2006** | **2007** | **2008** | **Thereafter** |
| Long-term debt, including current maturities | $2,144,000 | $ 240,000 | $ 550,000 | | | | $1,354,000 |
| Operating lease obligations | $ 47,197 | $ 8,928 | $ 4,290 | $ 3,786 | $ 3,679 | $ 3,451 | $ 23,063 |
| Purchase obligations: | | | | | | | |
| Product purchase commitments: | | | | | | | |
| Estimated payment obligations: | | | | | | | |
| Natural gas | $1,079,876 | $ 150,620 | $ 117,501 | $ 115,965 | $ 115,965 | $ 115,965 | $ 463,860 |
| NGLs | $ 131,904 | $ 15,745 | $ 8,935 | $ 8,935 | $ 8,935 | $ 8,935 | $ 80,419 |
| Petrochemicals | $1,149,987 | $ 425,971 | $ 373,174 | $ 327,171 | $ 23,671 | | |
| Other | $ 75,455 | $ 45,996 | $ 21,682 | $ 2,207 | $ 2,207 | $ 2,207 | $ 1,156 |
| Underlying major volume commitments: | | | | | | | |
| Natural gas (in Bbtus) | 164,032 | 23,602 | 17,790 | 17,520 | 17,520 | 17,520 | 70,080 |
| NGLs (in MBbls) | 5,333 | 578 | 366 | 366 | 366 | 366 | 3,291 |
| Petrochemicals (in MBbls) | 36,892 | 13,696 | 11,952 | 10,490 | 754 | | |
| Service payment commitments | $ 552 | $ 382 | $ 85 | $ 85 | | | |
| Capital expenditure commitments | $ 4,003 | $ 4,003 | | | | | |

The operating lease commitments shown in the preceding table exclude the non-cash related party expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability (the "retained leases"). The retained leases are accounted for as operating leases by EPCO. EPCO's minimum future rental payments under these leases are $12.1 in 2004, $2.1 million for each of the years 2005 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million in 2016.

EPCO has assigned to the Operating Partnership the purchase options associated with the retained leases. We notified the lessor of the isomerization unit associated with the retained leases of our intent to exercise the purchase option relating to this equipment in 2004. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million. Should we decide to exercise all of the remaining purchase options associated with the retained leases (which are also at fair value), up to an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016.

*Litigation*

We are sometimes named as a defendant in litigation relating to our normal business operations. Although we insure against various business risks, to the extent management believes it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of ordinary business activity. Management is not aware of any significant litigation, pending or threatened, that would have a significant adverse effect on our financial position or results of operations.

## 13. 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 chief executive officer. 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). 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 December 31, 2003 | $ 471,221 | $2,188,694 | $ 163,199 | $ 42,220 | $ 23,739 | $ 74,432 | $2,963,505 |
| Investments in and advances to unconsolidated affiliates (see Note 7): | | | | | | | |
| At December 31, 2003 | 88,801 | 645,958 | 33,000 | | | | 767,759 |
| Intangible Assets (see Note 8): | | | | | | | |
| At December 31, 2003 | 68,553 | 9,753 | 188,954 | 1,633 | | | 268,893 |
| Goodwill (see Note 8): | | | | | | | |
| At December 31, 2003 | 81,547 | 880 | | | | | 82,427 |

## 14. 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, primarily within our Processing segment. In general, the types of risks we attempt to hedge are those relating 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.

The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation methodologies. 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.

*Commodity financial instruments*

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 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 do utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas. Lastly, due to the nature of the transactions, we do not employ commodity financial instruments in our fee-based marketing business accounted for in 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 that we have established. 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 because of ineffectiveness. A financial instrument is generally regarded as “effective” when changes in its fair value almost fully offset changes in the fair value of the hedged item throughout the term of the instrument. Due to the complex nature of risks we attempt to hedge, our commodity financial instruments have generally not qualified as effective hedges under SFAS No. 133. As a result, changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. Mark-to-market accounting 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.

At December 31, 2003, we had open commodity financial instruments that will settle at different dates through December 2004. We routinely review our outstanding commodity financial instruments in light of current market conditions. If market conditions warrant, some instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the hedge to which the closed instrument relates.

We had a limited number of commodity financial instruments open at December 31, 2003. The fair value of these open positions at December 31, 2003 was an asset of $4 thousand (amount based on market prices on the date thereof).

*Interest rate hedging financial instruments*

Our interest rate exposure results from variable-interest rate borrowings and fixed-interest rate borrowings (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. Management oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

*Interest rate swaps*. We manage a portion of our interest rate risks by utilizing interest rate swaps. The objective of entering into interest rate swaps 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 notional amount while the other party pays a floating-interest 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 immaterial. We believe that it is prudent to maintain an appropriate balance of variable-rate and fixed-rate debt. There were no interest rate swaps outstanding at December 31, 2003.

*Treasury Locks*. During the fourth quarter of 2002, we entered into seven treasury lock transactions. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. Our treasury lock transactions carried an original maturity date of either January 31, 2003 or April 15, 2003. The purpose of these transactions was to hedge the underlying treasury interest rate associated with our anticipated issuance of debt in early 2003 to refinance the Mid-America and Seminole acquisitions. The notional amounts of these transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

Our treasury lock transactions were accounted for as cash flow hedges. We elected to settle all of the treasury locks by early February 2003 in connection with our Operating Partnership's issuance of Senior Notes C and D (see Note 9). The settlement of these instruments resulted in our receipt of $5.4 million of cash. This amount was recorded as a gain in other comprehensive income during the first quarter of 2003 and represents the effective portion of the treasury locks. The amount reclassified from accumulated other comprehensive income to earnings during 2003 was $0.4 million.

*Future issues concerning SFAS No. 133*

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 this guidance may be altered. As a result, additional adjustments may be recorded in future periods as we adopt new FASB interpretations.

**Fair value information**

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair value at year end due to their short-term nature. The estimated fair value of our fixed-rate debt is estimated based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. The fair values associated with our commodity and interest rate hedging financial instruments were developed using available market information and appropriate valuation techniques.

The following table summarizes the estimated fair values of our various financial instruments at December 31, 2003:

| **Financial instruments** | **Carrying Value** | **Fair Value** |
|---|---|---|
| Financial assets: | | |
| Cash and cash equivalents | $ 44,317 | $ 44,317 |
| Accounts receivable | 462,533 | 462,533 |
| Commodity financial instruments | 358 | 358 |
| Financial liabilities: | | |
| Accounts payable and accrued expenses | 801,498 | 801,498 |
| Fixed-rate debt (principal amount) | 1,734,000 | 1,849,327 |
| Variable-rate debt | 410,000 | 410,000 |
| Commodity financial instruments | 355 | 355 |



**15. 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. While we believe that we currently have adequate insurance to cover any adverse consequences resulting from our production of MTBE, we have been informed by our insurance carrier that upon renewal of our policy in April 2004, MTBE related claims may be excluded from the scope of our insurance coverage.

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 modification project is expected to be completed during the third quarter of 2004 at a total cost of approximately $30 million. 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. 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.